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March 24, 2006

BY HAND

Mr. Jeffrey Gregg
Environmental Analyst 2
New York State Department
of Environmental Conservation
Division of Environmental Permits
625 Broadway, 4th Floor
Albany, New York 12233-1750

Re: Broadwater Energy LLC – Joint Permit Application

Dear Mr. Gregg:

On behalf of our client, Broadwater Energy LLC (Broadwater), we are pleased to enclose an original and three copies of Broadwater's Application to the United States Army Corps of Engineers for Construction and Operation of the Broadwater LNG Terminal and Associated Pipeline in Long Island Sound, Long Island, New York (JPA).

By copy of this letter and pursuant to your request, we are also providing a copy of Broadwater's JPA to both Mr. Charles Hamilton and Mr. Charles DeQuillfeldt in the New York State Department of Environmental Conservation (NYSDEC) Stony Brook and East Setauket offices. Also by copy of this letter, we are providing a courtesy copy to Mr. Mike Vissichelli and Mr. Russell Smith at the United States Army Corps of Engineers (ACE) New York City office and to Mr. Alan Bauder at the New York State Office of General Services (NYSOGS).

If you have any questions or if we may be of further assistance, please contact me.

Thank you for your continued attention to this matter.

Very truly yours,

RJA

Robert J. Alessi

cc: (By FedEx)
Broadwater Energy LLC
Mr. Alan Bauder, NYSOGS Albany
Mr. Charles DeQuillfeldt, NYSDEC East Setauket
Mr. Michael Donnelly, Ecology & Environment, Inc.
Mr. Chuck Hamilton, NYSDEC Stony Brook
Mr. Russell Smith, ACE New York City
Mr. Mike Vissichelli, ACE New York City
94468

BROADWATER

APPLICATION TO THE UNITED STATES ARMY CORPS OF ENGINEERS FOR CONSTRUCTION AND OPERATION OF THE BROADWATER LNG TERMINAL AND ASSOCIATED PIPELINE IN LONG ISLAND SOUND LONG ISLAND, NEW YORK

PREPARED FOR:
BROADWATER ENERGY LLC

SUBMITTED TO:
UNITED STATES ARMY CORPS OF ENGINEERS
NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
NEW YORK STATE OFFICE OF GENERAL SERVICES

MARCH 2006

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List of Acronyms and Abbreviations

ABS	American Bureau of Shipping
ADCP	acoustic Doppler current profiler
AEO	Annual Energy Outlook
AGA	American Gas Association
AHT	anchor-handling tug
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
AT&T	American Telephone and Telegraph Company
bcf	billion cubic feet
bcfd	billion cubic feet per day
BOG	boil off gas
Btu	British thermal units
CEAB	Connecticut Energy Advisory Board
CFR	Code of Federal Regulations
CO	carbon monoxide
CSC	Cross Sound Cable
CWA	Clean Water Act
DC	direct current
DGPS	differential global positioning system
DOC	(United States) Department of Commerce
DP	dynamically positioned
DPDSV	dynamically positioned dive support vessel
DSV	dive support vessel
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
ESD	emergency shutdown
ESDS	emergency shutdown system
FBE	fusion-bonded epoxy
FERC	Federal Energy Regulatory Commission
FSRU	floating storage and regasification unit
GBS	gravity-based structure
IG	inert gas
IGTS	Iroquois Gas Transmission System
INS	Immigration and Naturalization Service
ISA	Instrument Society of America
ISO	International Standards Organization
km	kilometer
LNG	liquefied natural gas
m	meter
m^2	square meter
m^3	cubic meter
MAOP	maximum allowable operating pressure
MBR	marine bioreactor

mcf	thousand cubic feet
mg/L	milligrams per liter
mmcfd	million cubic feet per day
MP	milepost (along subsea connecting pipeline)
MPN	Most Probable Number
MSS	mooring support structure; also Manufacturers Standardization Society of the Valve and Fitting Industry
MW	megawatt
NACE	National Association of Corrosion Engineers
NEEC	Northeast U.S. and Eastern Canada
NEPA	National Environmental Policy Act
NGA	Natural Gas Act
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxides
NYISO	New York Independent System Operator
NYS	New York State
NYSDEC	New York State Department of Environmental Conservation
NYSDOS	New York State Department of State
NYSDPS	New York State Department of Public Service
NYSECL	New York State Environmental Conservation Law
NYSERDA	New York State Energy Research and Development Agency
NYSOGS	New York State Office of General Services
NYSOPRHP	New York State Office of Parks Recreation and Historic Preservation
OBS	optical backscatter
℃	degrees Celsius
OCIMF	Oil Companies International Marine Forum
℉	degrees Fahrenheit
OSHA	Occupational Safety and Health Administration
PAHs	polycyclic aromatic hydrocarbons
PCHE	printed circuit heat exchanger
ppm	parts per million
ppt	parts per thousand
psi	pounds per square inch
ROV	remotely operated vehicle
RTJ	ring-type joint
SCADA	supervisory control and data acquisition
SCR	selective catalytic reduction
SCV	submerged combustion vaporization
SO_2	sulfur dioxide
SPCC	Spill Prevention, Control, and Countermeasures
SPDES	State Pollutant Discharge Elimination System
SRV	shuttle regasification vessel
SSSV	subsea-subsurface safety valve
STV	shell and tube vaporization
tcf	trillion cubic feet
tonne	metric ton (equal to 1,000 kg or 2,204 pounds)

TSS	total suspended solids
UBC	Uniform Building Code
USACE	United States Army Corps of Engineers
USCG	United States Coast Guard
USDOE	United States Department of Energy
USDOT OPS	United States Department of Transportation Office of Pipeline Safety
USDOT	United States Department of Transportation
USFWS	United States Fish and Wildlife Service
VOCs	volatile organic compounds
WHRU	waste heat recovery unit
YMS	yoke mooring system

95-19-3 (8/00) pfp

JOINT APPLICATION FOR PERMIT

New York State
United States Army Corps of Engineers

Applicable to agencies and permit categories listed in Item 1. Please read all instructions on back. Attach additional information as needed. Please print legibly or type.

1. Check permits applied for:

NYS Dept. of Environmental Conservation

- [ ] Stream Disturbance (Bed and Banks)
- [X] Navigable Waters (Excavation and Fill)
- [ ] Docks, Moorings or Platforms (Construct or Place)
- [ ] Dams and Impoundment Structures (Construct, Reconstruct or Repair)
- [ ] Freshwater Wetlands
- [ ] Tidal Wetlands
- [ ] Coastal Erosion Control
- [ ] Wild, Scenic and Recreational Rivers
- [X] 401 Water Quality Certification
- [ ] Potable Water Supply
- [ ] Long Island Wells
- [ ] Aquatic Vegetation Control
- [ ] Aquatic Insect Control
- [ ] Fish Control

NYS Office of General Services (State Owned Lands Under Water)

- [X] Lease, License, Easement or other Real Property Interest Utility Easement (pipelines, conduits, cables, etc.)
- [ ] Docks, Moorings or Platforms (Construct or Place)

Adirondack Park Agency

- [ ] Freshwater Wetlands Permit
- [ ] Wild, Scenic and Recreational Rivers

Lake George Park Commission

- [ ] Docks (Construct or Place)
- [ ] Moorings (Establish)

US Army Corps of Engineers

- [X] Section 404 (Waters of the United States)
- [X] Section 10 (Rivers and Harbors Act)
- [ ] Nationwide Permit (s) Identify Number(s)

For Agency Use Only:
DEC APPLICATION NUMBER

US ARMY CORPS OF ENGINEERS

2. Name of Applicant (Use full name) Broadwater Energy LLC (Murray Sondergard - Project Director)
Telephone Number (daytime) (403) 920-2046
Mailing Address Murray Sondergard, Broadwater Energy LLC c/o Robert J. Alessi, Esq., LeBoeuf, Lamb, Greene & MacRae LLP
Post Office 99 Washington Ave., Suite 2020, Albany **State** NY **Zip Code** 12210-2820

3. Taxpayer ID (If applicant is not an individual) Application pending. To be provided upon receipt.

4. Applicant is a/an: (check as many as apply) [X] Owner [ ] Operator [ ] Lessee [ ] Municipality / Governmental Agency

5. If applicant is not the owner, identify owner here - otherwise, you may provide Agent/Contact Person information.
Owner or Agent/Contact Person [ ] Owner [X] Agent /Contact Person
Robert J. Alessi, Esq.
Telephone Number (daytime) (518) 626-9000
Mailing Address LeBoeuf, Lamb, Greene & MacRae LLP 99 Washington Avenue, Suite 2020
Post Office Albany **State** NY **Zip Code** 12210-2820

6. Project / Facility Location (mark location on map, see instruction 1a.)
County: Suffolk Town/City/Village: Smithtown/Brookhaven/Riverhead Tax Map Section/ Block /Lot Number:
Location (including Street or Road) Long Island Sound/Port Jefferson/Greenport **Telephone Number** (daytime)
Post Office **State** **Zip Code**

7. Name of Stream or Waterbody (on or near project site) Long Island Sound

8. Name of USGS Quad Map: New Haven Ct 1:100k quad
Location Coordinates: see attached NYTM-E NYTM-N 4

9. Project Description and Purpose: (Category of Activity e.g. new construction/installation, maintenance or replacement; Type of Structure or Activity e.g. bulkhead, dredging, filling, dam, dock, taking of water; Type of Materials and Quantities; Structure and Work Area Dimensions; Need or Purpose Served)

See Section 2.1

10. Proposed Use: [ ] Private [ ] Public [X] Commercial

11. Will Project Occupy State Land? [X]* Yes [ ] No

12. Proposed Start Date:

13. Estimated Completion Date:

14. Has Work Begun on Project? (If yes, attach explanation of why work was started without permit.) [ ] Yes [X] No

15. List Previous Permit / Application Numbers and Dates: (If Any)

16. Will this Project Require Additional Federal, State, or Local Permits? [X] Yes [ ] No
If Yes, Please List: * see attached, including additional responses to Form 95-19-3

17. If applicant is not the owner, both must sign the application
I hereby affirm that information provided on this form and all attachments submitted herewith is true to the best of my knowledge and belief. False statements made herein are punishable as a Class A misdemeanor pursuant to Section 210.45 of the Penal Law. Further, the applicant accepts full responsibility for all damage, direct or indirect, of whatever nature, and by whomever suffered, arising out of the project described herein and agrees to indemnify and save harmless the State from suits, actions, damages and costs of every name and description resulting from said project. In addition, Federal Law, 18 U.S.C., Section 1001 provides for a fine of not more than $10,000 or imprisonment for not more than 5 years, or both where an applicant knowingly and willingly falsifies, conceals, or covers up a material fact; or knowingly makes or uses a false, fictitious or fraudulent statement.

Date March 23/06 Signature of Applicant [signature] Title PROJECT DIRECTOR

Date MARCH 23/06 Signature of Owner [signature] Title PROJECT DIRECTOR

PUBLIC

BW003970

General Instructions

Incomplete or inaccurate information may delay processing and a final decision on your application

A. Type or print clearly in ink. Attach FIVE copies of additional information required in i. through iii. below.
  i. A USGS map, or equivalent showing the project location. Include on the map wetlands, seasonally wet streams and ditches.
  ii. A sketch plan drawn to scale or with dimensions given or engineering drawings showing location and extent of work as well as view directions of the photographs required in iii.
  iii. At least three (3) representative color photographs of the project area and surroundings with time and date when they were taken indicated.
B. Applications by counties, cities, towns, and villages must be signed by the chief executive of that municipality or the head of the department or agency undertaking the project.
C. "Owner" in application item 4 holds title to the land, facility, easement or right-of-way on which the project will be undertaken. If someone other than the owner is the applicant, written consent of the owner to use the property or facility must accompany the application.
D. The applicant is responsible for obtaining any other federal, state or local permits. Separate authorization or letter of **No Jurisdiction** should be received from the **Department of Environmental Conservation (DEC), Office of General Services (OGS), Adirondack Park Agency (APA) or Lake George Park Commission (LGPC)** and the **Army Corps of Engineers (ACOE)** prior to initiation of work in wetlands or waterways.
E. Location Coordinates (section 8) are expressed in New York Transverse Mercator units or NYTMs (UTM Zone 18 expanded to encompass the entire state). These are based on the North American Datum 1983. If you are able to supply accurate coordinates, please do so. Otherwise the Department will determine them.

Other Requirements

F. If project is an unlisted action pursuant to the State Environmental Quality Review Act regulations - 6 NYCRR Part 617, a completed Part 1 of a Short Environmental Assessment Form must be submitted with the application.
G. If project is a Type 1 action pursuant to the State Environmental Quality Review Act regulations - 6 NYCRR Part 617, a completed Part 1 of a Full Environmental Assessment Form must be submitted with the application.
H. If project is classified as major pursuant to the Uniform Procedures Act regulations - 6 NYCRR Part 621, a completed Part 1 of a Structural Archeological Assessment Form must be submitted with the application.
I. If project requires a federal permit and lies within the Coastal Zone, a completed Federal Consistency Assessment Form must be submitted with the application.
J. If project is within the Adirondack Park, additional information is required by the APA to fully determine permitting applicability.

Special Requirements for Specific Permit Applications

K. Applications for the construction, reconstruction, or repair of a DAM or other IMPOUNDMENT STRUCTURE must be accompanied by Supplement D-1.
L. Applications for DOCK, PLATFORM, or MOORING facility permits must be accompanied by Supplement D-2.
M. Applications for Water Supply or Long Island Well permits must be accompanied by Supplement W-1.
N. Applications for a permit to apply a Chemical to control or eliminate Aquatic Vegetation, Fish or Insects must be accompanied by the proper supplemental form available from the department.
O. Applications for a Wild, Scenic, or Recreational Rivers permit must be accompanied by Supplement WSR-1.
P. Applications for a permit to disturb a wetland or waterway by placing fill or performing mechanized land clearing, ditching, channelization, dredging, or excavation activities under Section 404 of the Clean Water Act or Article 24 and 25 of the Environmental Conservation Law should provide a discussion of practicable alternatives considered to avoid, minimize and /or mitigate the proposed project impacts. Particular justification should be given as to why the alternatives are not suitable.

Contact the Regional Permit Administrator, Division of Environmental Permits, at the appropriate DEC office, OGS, APA, LGPC permitting agent, or the respective Corps District Office, as given below, for assistance regarding any of the above requirements. Consult other available application instruction materials for the appropriate permit types.

New York State Agencies:

Distribution 1ST COPY Permit Administrator 2ND COPY Corps of Engineers 3RD COPY Program 4TH COPY NYS Agency 5TH COPY Applicant

Department of Environmental Conservation

REGION 1
Building 40, SUNY
Stony Brook, NY 11790-2356
(631) 444-0365

REGION 2
1 Hunter's Point Plaza
47-40 21st Street
Long Island City, NY 11101-5407
(718) 482-4497

REGION 3
21 South Putt Corners Road
New Paltz, NY 12561-1696
(845) 256-3054

REGION 4
1150 North Wescott Road
Schenectady, NY 12306-2014
(518) 357-2069

REGION 4 Sub-Office
Route 10
HCR #1 Box 3A
Stamford NY 12167-9503
(607) 652-7741

REGION 5
Route 86, PO Box 296
Ray Brook NY 12977-0296
(518) 897-1234

REGION 5 Sub-Office
P.O. Box 220
Warrensburg, NY 12885-0220
(518) 623-1281

REGION 6
State Office Building
317 Washington Street
Watertown, NY 13601-3787
(315) 785-2245

REGION 6 Sub-Office
State Office Building
207 Genesee Street
Utica, NY 13501-2885
(315) 793-2555

REGION 7
615 Erie Blvd West
Syracuse, NY 13204-2400
(315) 426-7438

REGION 7 Sub-Office
1285 Fisher Avenue
Cortland, NY 13405-1090
(607) 753-3095

REGION 8
6274 E. Avon - Lima Road
Avon, NY 14414-9519
(716) 226-2466

REGION 9
270 Michigan Avenue
Buffalo NY 14203-2999
(716) 851-7165

REGION 9 Sub-Office
182 East Union,
Suite 3
Allegany, NY 14706-1328
(716) 372-0645

Office of General Services

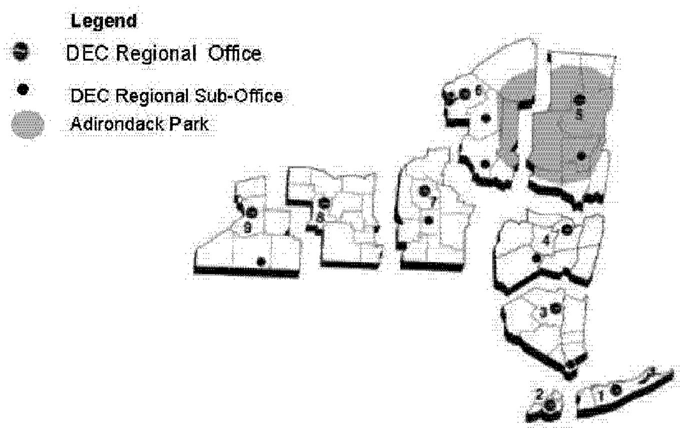
Division of Land Utilization
Bureau of Land Management
Corning Tower, Empire State Plaza
Albany, NY 12242
(518) 474-2195

Adirondack Park Agency

PO Box 99
Ray Brook NY 12977
(518) 891-4050

Lake George Park Commission

P.O. Box 749 Fort George Road
Lake George NY 12845-0749
(518) 668-9347



United States Army Corps of Engineers

Department of the Army ATTN: Regulatory Branch
New York District, Corps of Engineers, 26 Federal Plaza, New York NY 10278-0090
Telephone
(212) 264-6731 for DEC Regions 1,2 and Westchester and Rockland Counties
(212) 264-0185 for DEC Region 3 except Westchester and Rockland Counties

Albany Field Office Telephone (518) 270-0588 / 0589 - DEC regions 4,5
1 Bond Street, Troy NY 12180

Buffalo District, Corps of Engineers Telephone (716) 879-4330 - DEC regions 6, 7, 8, 9
1776 Niagara Street, Buffalo NY 14207-3199

Additional Responses for Form 95-19-3

Box 6 Project/Facility Location

The proposed Broadwater liquefied natural gas (LNG) terminal will be located in Long Island Sound (the Sound), approximately 9 miles (14.5 kilometers [km]) from the shore of Long Island in New York State waters, offshore of Riverhead, Suffolk County, New York as shown on Figure 1-1.

The Project is located within Long Island Sound on and surrounded by lands underlying state waters that fall under the ownership of the state of New York. As part of the submittal, Broadwater is applying for appropriate easement agreements from the New York State Office of General Services (NYSOGS).

Broadwater also proposes to construct natural gas pipeline beneath the seafloor, from the floating storage and regasification unit (FSRU) tower structure to an interconnection location at the existing Iroquois Gas Transmission System (IGTS) pipeline, approximately 21.7 miles west of the proposed FSRU site (*see* Figure 1-1). The pipeline will be located in the Suffolk County Towns of Riverhead, Brookhaven and Smithtown.

The location of existing onshore facilities in that will support construction and operation of the facilities have not been finalized but are described below in Section 2.

Box 8 Project Location Coordinates

The Project location coordinates are provided in Table 1-1 and are depicted on Figure 1-1.

Table 1-1 RPLs UTM Zone 18, NAD 83, Broadwater LNG Project

Location	X	Y

Table 1-1 contains Critical Energy Infrastructure Information and has been removed from this volume. Procedures for obtaining access to Critical Energy Infrastructure Information (CEII) may be found at 18 CFR 388.113. Requests for access to CEII should be made to the Commission's CEII Coordinator.

Table 1-1 RPLs UTM Zone 18, NAD 83, Broadwater LNG Project

Location	X	Y

Table 1-1 contains Critical Energy Infrastructure Information and has been removed from this volume. Procedures for obtaining access to Critical Energy Infrastructure Information (CEII) may be found at 18 CFR 388.113. Requests for access to CEII should be made to the Commission's CEII Coordinator.

Datum: NAD 83
Spheroid: Clarke 1886
Projection: UTM
Zone: 18N

Box 9 Project Description

See Section 2.1 of this document.

Box 16 Required Permits

The federal and state entities and the environmental permits, consultations, and clearances that may be required for approval to construct and operate the Project are identified below in Tables 1-2 and 1-3.

This application is filed subject to applicable federal and other law and retained rights and without waiver of or prejudice to such law/rights and the rights of Broadwater.

Table 1-2 List of Federal Permits, Approvals, and Consultations

Agency	Act	Permit/Approval
FERC	Natural Gas Act (NGA) 15 U.S.C. 717 et seq., 18 CFR Part 153, Subpart B (2002)	Sections 3 and 7 approvals to site, construct and operate the LNG terminal and to construct and operate the subsea connecting pipeline facilities, including the pipeline riser and mooring tower, respectively
USCG	The Maritime Transportation Security Act of 2002	Review process – project must be compatible with National and Area Marine Security Plans
	33 CFR § 127	Letter of Recommendation
Advisory Council on Historic Preservation	National Historic Preservation Act, Section 106	Review of project effects on cultural resources
EPA	Clean Water Act, Section 401 and 404	Review of Section applications
	Clean Air Act	Prevention of Significant Deterioration, New Source Review

Table 1-2 List of Federal Permits, Approvals, and Consultations

Agency	Act	Permit/Approval
[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]

Table 1-3 List of State Permits and Approvals

Agency	Act	Permit/Approval
[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
		[illegible]

Table 1-3 List of State Permits and Approvals

Agency	Act	Permit/Approval
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]

Figure 1-1 contains Critical Energy Infrastructure Information and has been removed from this volume. Procedures for obtaining access to Critical Energy Infrastructure Information (CEII) may be found at 18 CFR 388.113. Requests for access to CEII should be made to the Commission's CEII Coordinator.

2. PROJECT DESCRIPTION

2.1 PROJECT DESCRIPTION

Broadwater Energy, a joint venture between TCPL USA LNG, Inc., and Shell Broadwater Holdings LLC, proposes to construct and operate a marine LNG terminal and subsea connecting pipeline for the importation, storage, regasification, and transportation of natural gas. The Broadwater LNG Project (the Project) will increase the availability of natural gas to the New York and Connecticut markets through an interconnection with the IGTS pipeline.

Broadwater is filing this Joint Application for Permit with the New York District of the U.S. Army Corps of Engineers (USACE) and New York State Department of Environmental Conservation, seeking all of the necessary authorizations pursuant to Section 10 of the Rivers and Harbors Act, Section 404 of the Clean Water Act, Section 401 of the Clean Water Act (SPDES permit applications are being filed concurrently with this application), and New York State Environmental Conservation Law (NYSECL) Article 15, Title 5 (Protection of Waters).

The primary components of the Broadwater Project include the following new facilities: (1) an LNG regasification facility consisting of an FSRU hull incorporating LNG receiving and storage, mooring system, process facilities, utility systems, ancillary facilities, and safety systems; and (2) an approximately 21.7-mile-long subsea connecting pipeline. In addition, the project will require both temporary and permanent onshore facilities during construction and operation of the Project. To the extent practicable, Broadwater proposes to use existing onshore facilities to avoid or minimize any additional environmental impact associated with the onshore facilities.

2.1.1 Offshore Facilities

FSRU

The proposed Broadwater LNG terminal will be located in Long Island Sound (the Sound), approximately 9 miles (14.5 kilometers [km]) from the shore of Long Island in New York State waters, offshore of Riverhead, Suffolk County, New York, as shown on Figure 2-1. The nearest Connecticut onshore point is approximately 10 miles from the proposed terminal location. The LNG terminal facilitates the sea-to-land transfer of natural gas. It will be designed to receive, store, and regasify LNG at an average throughput of 1.0 billion cubic feet per day (bcfd) and will be capable of delivering a peak throughput of 1.25 bcfd. The Project will deliver the regasified LNG to the existing interstate natural gas pipeline system via an interconnection to the IGTS pipeline.

The proposed LNG terminal will consist of a floating storage and regasification unit (FSRU) with a steel hull that is approximately 1,215 feet (370 meters [m]) in length, 200 feet (60 m) in width, and rising approximately 80 feet (25 m) above the water line to the

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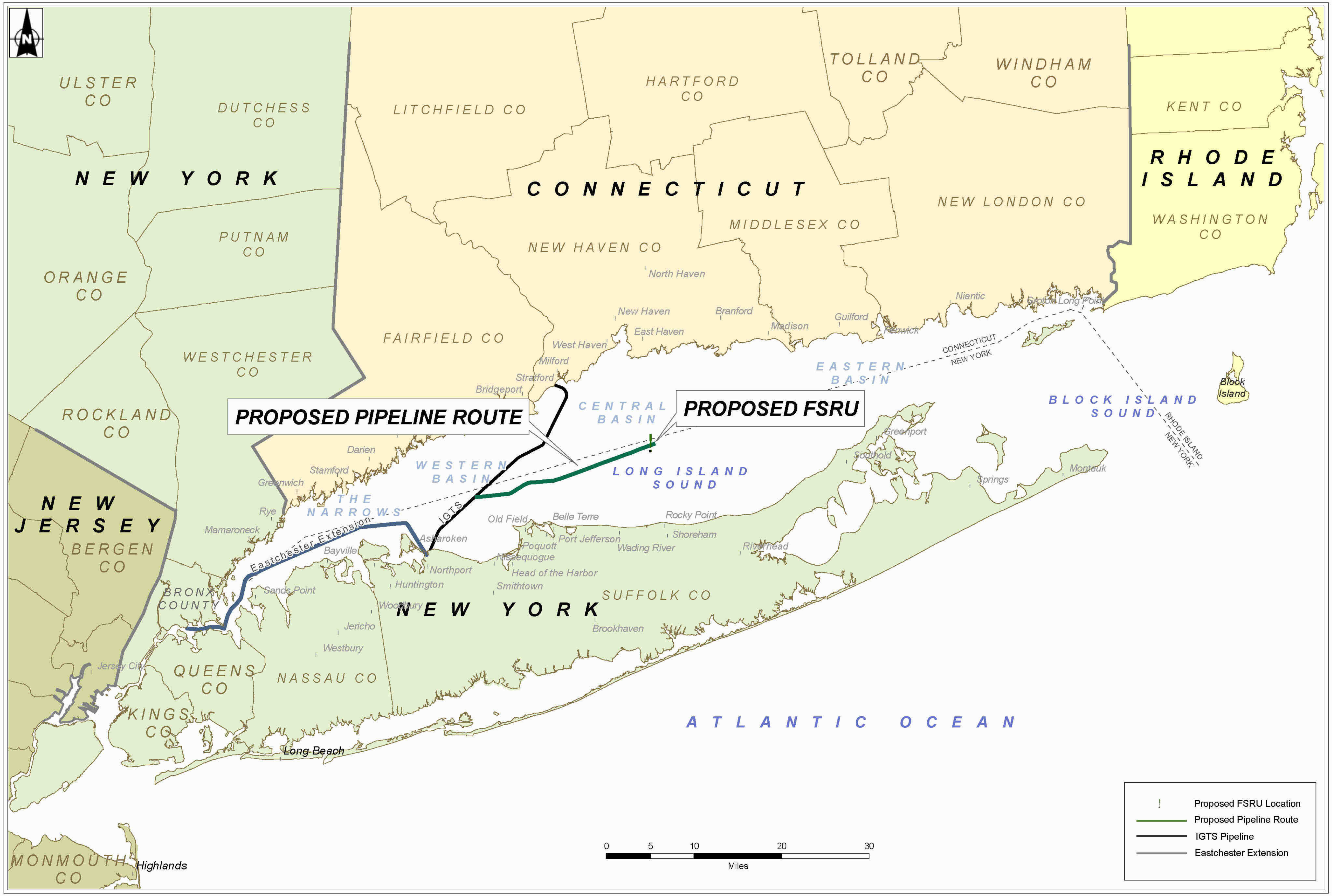

Source: ESRI StreetMap, 2002.

Figure 2-1
Proposed Broadwater Project Location in Long Island Sound

trunk deck, as shown on Figure 2-2. The FSRU's draft is approximately 40 feet (12 m). The freeboard and mean draft of the FSRU will generally not vary throughout operating conditions. This is achieved by ballast control to maintain the FSRU's trim, stability, and draft. The FSRU will be designed with a net storage capacity of approximately 350,000 cubic meters [m^3] of LNG (equivalent to 8 billion cubic feet [bcf] of natural gas) with base vaporization capabilities of 1.0 bcfd using a closed-loop shell and tube vaporization (STV) system. The LNG will be delivered to the FSRU in LNG carriers with cargo capacities ranging from approximately 125,000 m^3 up to a potential future size of 250,000 m^3 at the frequency of two to three carriers per week.

The FSRU will be secured in place in Long Island Sound via a yoke mooring system (YMS) attached to a tower structure that is secured to the seabed. The YMS and tower structure allow the vessel to orient in response to the prevailing wave, wind, and current conditions. The FSRU will be equipped with electrically powered azimuth stern thrusters to assist if required to maintain a constant heading during mooring operations with LNG carriers. The FSRU will have a single berth on its starboard side to accommodate a single LNG carrier for off-loading of LNG. Living quarters to accommodate approximately 30 permanent and 30 temporary (i.e., during commissioning, training, shutdowns and maintenance) crew members will be located on the facility aft of the LNG storage and containment area.

The FSRU will be connected to the send-out pipeline, which rises from the seabed and is supported by the stationary tower structure associated with the YMS. The tower, which is secured to the seabed by four tubular legs that will be pile-driven into the Sound floor to a depth of 230 ft (70 m), will house the YMS, allowing the FSRU to weathervane around the tower. The total area under the tower structure, which is of open design, will be approximately 13,180 square feet (1,225 square meters [m^2]).

A safety and security zone will be established around the FSRU location to provide additional safety and security of the facility. The nature and extent of this zone will be determined by the USCG. A right-of-way lease from the NYSOGS is expected to be obtained for both the mooring tower and the connecting pipeline.

Pipeline

Broadwater will also construct an approximately 21.7-mile, 30-inch-diameter natural gas pipeline to deliver the vaporized natural gas to the existing IGTS pipeline that crosses western Long Island Sound between Milford, Connecticut, and Northport, Long Island (*see* Figure 2-1). It will be installed beneath the seafloor from the stationary tower structure to an interconnection location at the existing 24-inch-diameter subsea section of the IGTS pipeline, approximately 21.7 miles west of the proposed FSRU site. Figure 2-1 presents the proposed pipeline route.

It is anticipated that the subsea connecting pipeline will be constructed within a 300-foot construction right-of-way that will generally encompass the maximum lateral width of disturbance due to trench excavation. The actual width of disturbance from the


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pipelaying and installation activities is anticipated to be approximately 75 feet, encompassing both the pipeline trench and adjacent spoil piles generated during the subsea plowing of the seabed to install the pipeline. Pipelaying and installation will require the use of anchored vessels. A wider, approximately 4,000-foot-wide construction corridor will be required to allow placement of anchors to stabilize the construction vessels.

To stabilize and protect the operating components, sections of the pipeline will be covered with engineered back-fill material or spoil removed during the lowering operation.

Following installation of the pipeline, a permanent 30-foot right-of-way centered on the as-built pipeline location will be established for operation of the facility. The temporary and permanent easements will be granted by the NYSOGS.

2.1.2 Onshore Facilities

Temporary and permanent onshore facilities will be required during construction and operation of the Project. To the extent practicable, Broadwater proposes to use existing onshore facilities to avoid or minimize any additional environmental impact associated with the onshore facilities. Temporary onshore facilities will be required for concrete-coating operations, pipe storage, docking, onshore storage, and office space. Broadwater will require permanent onshore facilities, including office space, warehousing, and waterfront access.

Broadwater will utilize concrete-coated pipe for its proposed subsea pipeline. The concrete weight coating will be applied to the pipe at an existing off-site concrete coating plant at a location to be determined during detailed design.

Following completion of concrete coating, the pipe will be transported via rail to an existing port lay-down and storage area with adequate land-to-sea transfer capabilities, likely in the Port of New York/New Jersey. The actual location of the storage area will be determined during detailed design. No pipe storage areas will be needed on lands adjacent to Long Island Sound.

During the course of construction, the contractor will need temporary space on the shore of Long Island Sound, primarily for shuttling personnel and supplies to the Project site. The only waterfront facility required to support construction activities will be a dock. Based on the amount of existing dockage available in Port Jefferson, Broadwater believes that existing facilities are adequate and that no new waterfront facilities will be needed. The contractor may require the use of an onshore office and warehouse facilities to support offshore activities during construction. The selected contractor will identify these locations prior to construction. However, based on the adequacy of existing office and warehouse space, Broadwater does not anticipate the need to construct new facilities to support temporary construction needs.

Broadwater will require permanent onshore facilities, including office space, warehousing, and waterfront access. Broadwater anticipates leasing existing facilities that require only minor modifications for these purposes, and no land acquisition is proposed. These facilities will be located within existing facilities that are operated by others. Potential locations have been identified in Greenport and Port Jefferson, New York (see Figures 2-3 and 2-4). The most critical components of the onshore facilities are the requisite waterfront access, which will allow waterborne transport to the FSRU from shore. The primary purpose of the waterfront facilities will be for tug mooring, personnel transfer, and materials transfer, each of which is described in detail in Resource Report 1 of the Onshore Facilities document. Broadwater anticipates leasing existing marine facilities for these purposes. Minor modifications may be required to maintain adequate security. Gated access with security controls that are manned at all times will be required at the waterfront access facility. Broadwater may need to install security fencing and controls.

2.1.3 Project Components

2.1.3.1 FSRU Facilities

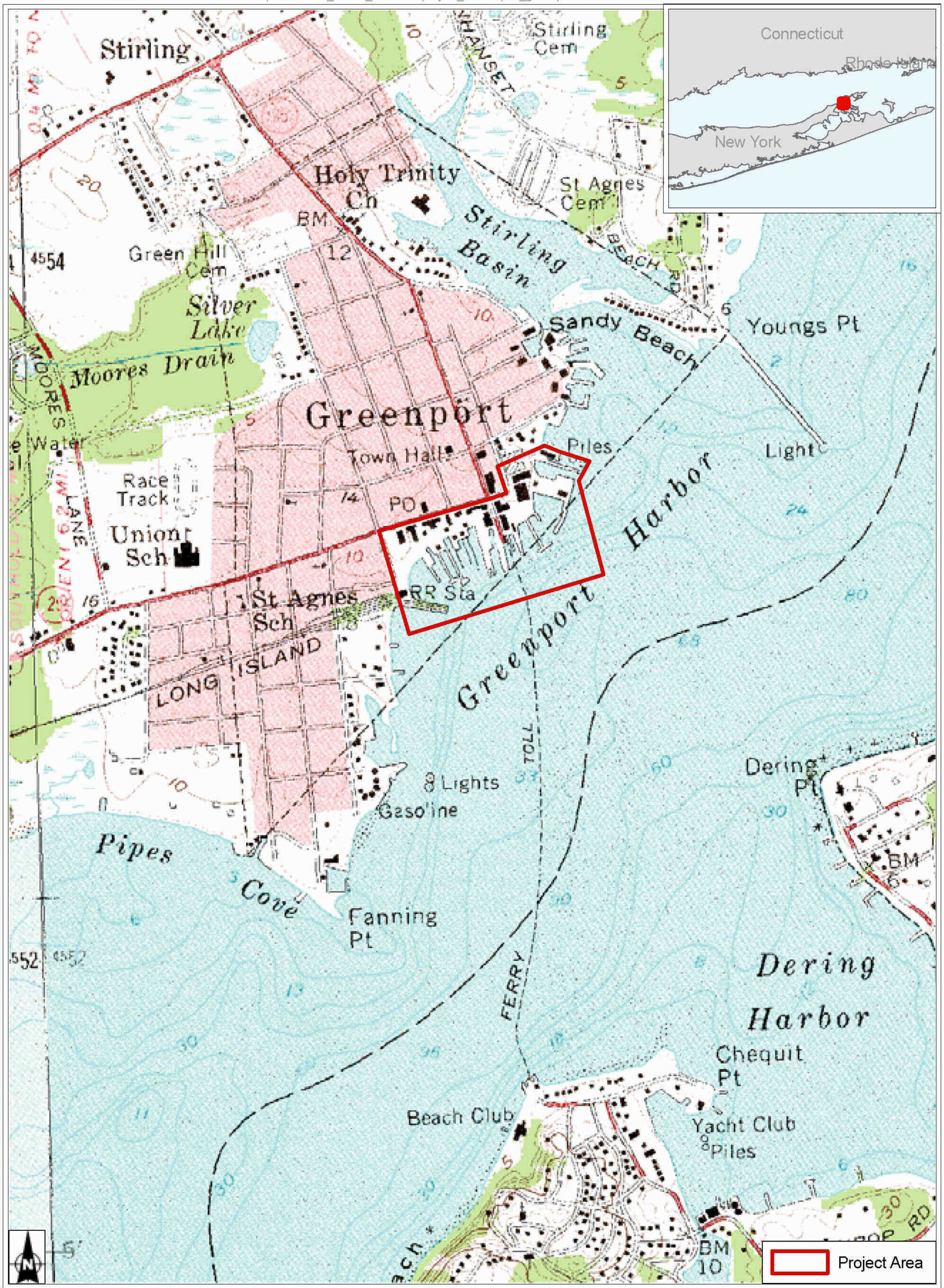
2.1.3.1.1 Overview of FSRU

The preliminary design of the FSRU, as described below, will be finalized upon Project authorization, and will be built to conform to International Maritime Organization standards. A third party ship classification society such as the American Bureau of Shipping (ABS) will verify and certify the final design and construction. Primary FSRU components, which are discussed in greater detail below, include:

- A Yoke Mooring System;
- LNG Storage and Vaporization Facilities;
- LNG Receiving Facilities;
- Power Generation;
- A Ballasting System;
- Utilities;
- Storm Water Handling;
- Crew Accommodations and Command and Control Facilities; and
- Safety System.

The FSRU would be constructed at an overseas shipyard that has yet to be selected. The selection of a shipyard will be made on an international basis with an assessment of the shipyard's capacity, ability, and proven track record for LNG shipbuilding project construction. Options would be:

- Daewoo Shipbuilding & Marine Engineering, Korea
- Samsung Heavy Industries, Korea
- Hyundai Heavy Industries, Korea
- Mitsubishi Heavy Industries, Japan
- Mitsui Engineering & Shipbuilding, Japan
- Chantiers de l'Atlantique, France
- IZAR Construcciones Navales, Spain



Source: USGS Greenport, 1956; Southold, 1956.

0 0.1 0.2 0.4

Miles

Figure 2-3 Proposed Onshore Facility Location Greenport, New York

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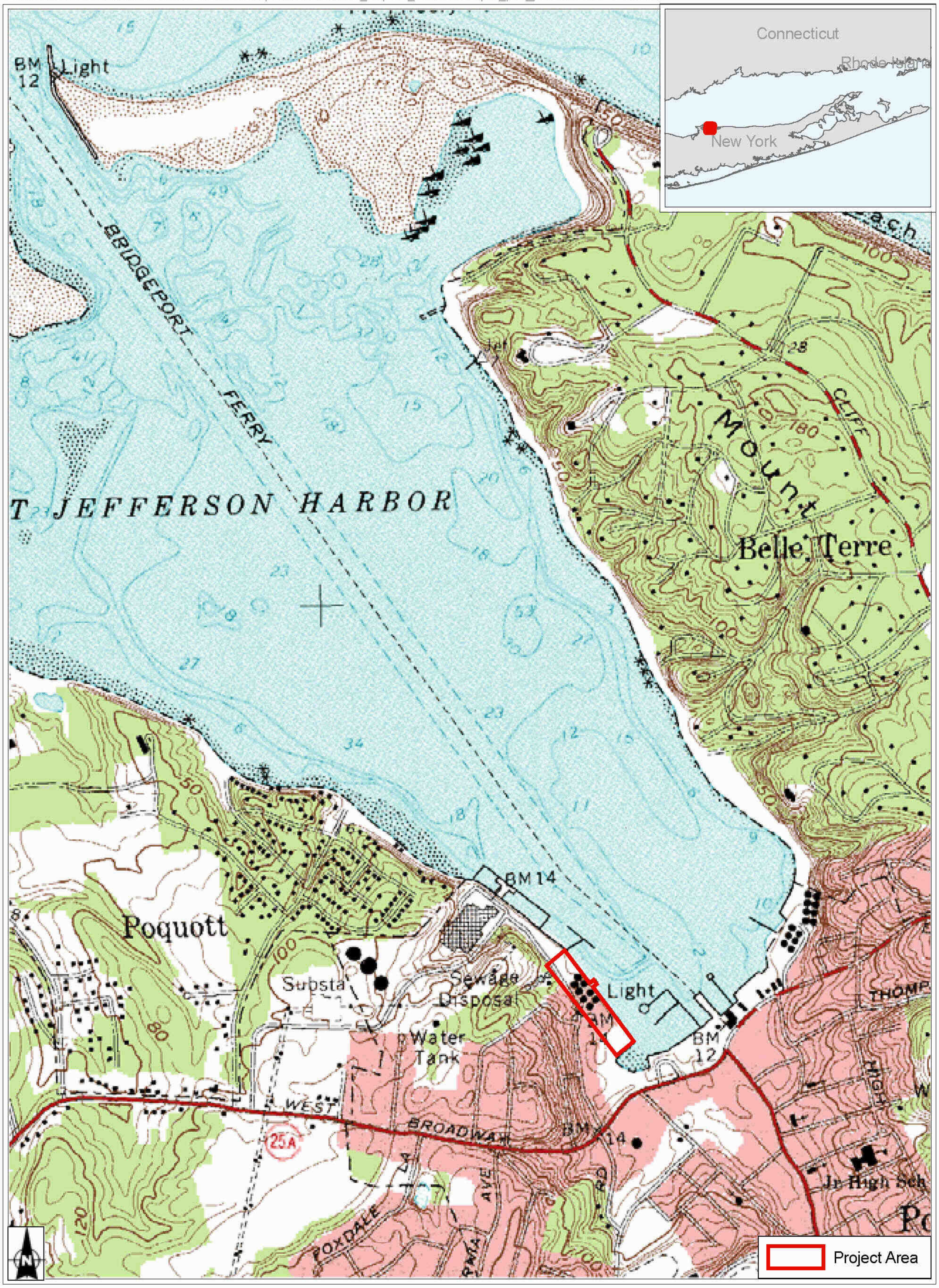

Source: USGS Port Jefferson, 1967.

0 0.125 0.25 0.5
Miles

**Figure 2-4 Proposed Onshore Facility Location
Port Jefferson, New York**

A facility to construct the YMS has not been determined at this time. The selection of a suitable contractor and facility will be made on an international basis with an assessment of the contractor's capacity, ability, and proven track record for this type of project construction. The construction site is expected to be the same shipyard selected for the FSRU.

A U.S. shipyard may be considered for construction of the FSRU or the YMS only if no changes to structure and operation of the shipyard would be required to construct the FSRU and/or its mooring system.

The FSRU itself will be non-propelled but will be equipped with one pair of stern azimuth thrusters. The FSRU will be a vessel-shaped, double-hulled facility, built specifically to transfer, store and regasify LNG. Material for hull construction for the FSRU will be of mild steel (structural steel that contains low amounts of carbon—the most common form of steel) and higher tensile steel, which will be approved by the appropriate ship classification society.

In addition to the facilities discussed below, the FSRU will include additional on-deck structures. The FSRU will be equipped with three deck cranes for equipment and supply distribution. A helideck for emergency transport will be located on top of the accommodations, as well as a single combined signal and radar mast. A flare stack, extending approximately 197 ft (60 m) above the trunk deck, will be located toward the fore of the FSRU and will be used for only emergency venting or flaring of natural gas. The flare stack will not be used under normal operational conditions and will utilize an automatic pilot light.

The FSRU hull is of double hull design similar to that of an LNG carrier. The double hull is applicable to the flat bottom, sides and upper/trunk decks of the FSRU such that the entire cargo containment system is protected by a double hull.

To protect the hull of the FSRU from any LNG spill that may occur, drainage is managed by providing the coaming and draining systems that diverts LNG to a disposal point on the port side of the FSRU. The disposal point is determined such that there would be no interference with any other vessel that may be in the immediate vicinity of the FSRU. LNG spills from loading arms are also mitigated using stainless steel cladding on parts of the FSRU hull at loading points, combined with a water-curtain spray. Resource Report No. 13 contains LNG spill details.

2.1.3.1.2 Major Equipment on Deck

The FSRU has various regasification process and utility equipment mounted on deck, as depicted on Figure 2-5 and described below.

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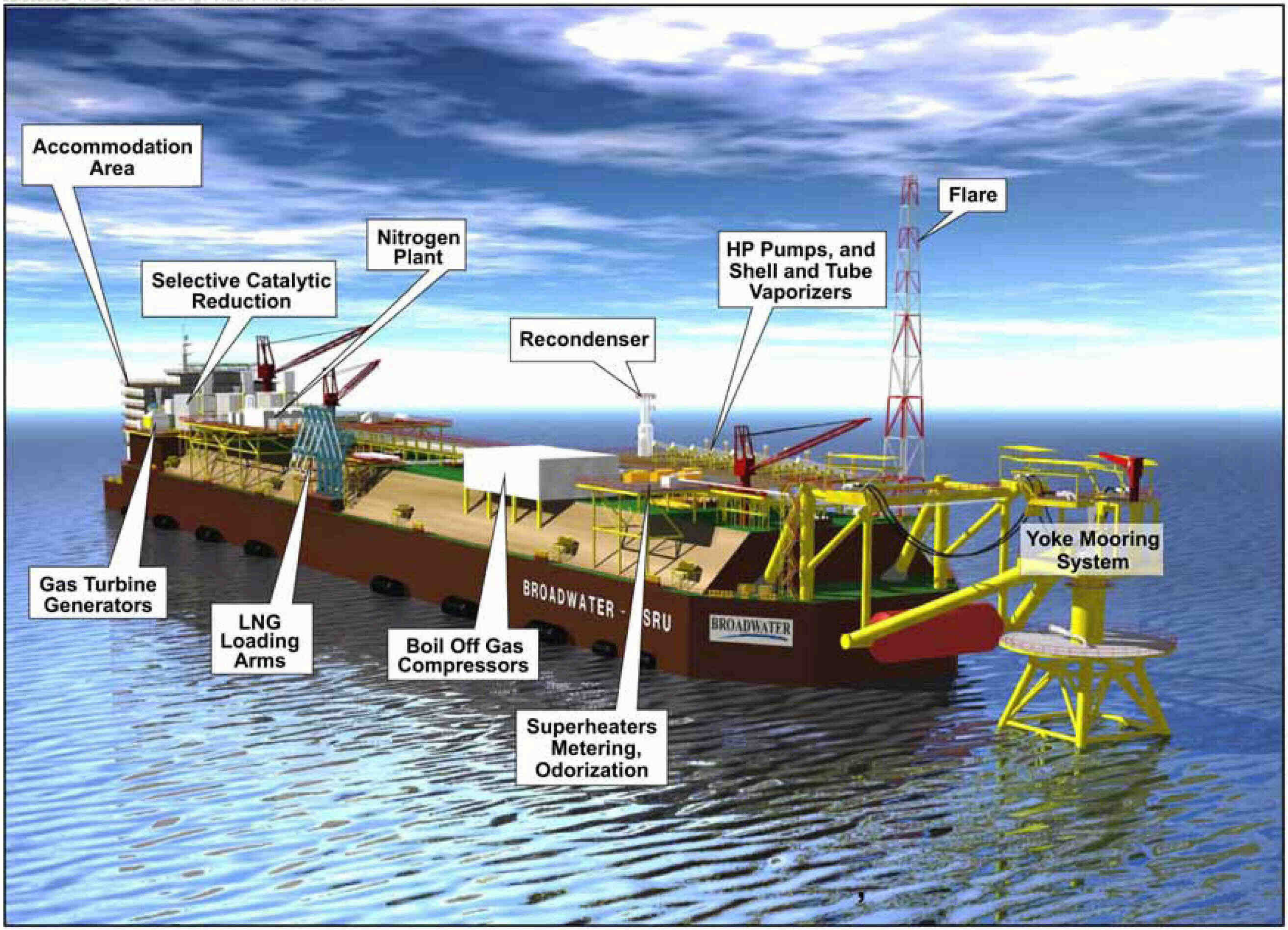

Figure 2-5 Detailed Depiction of FSRU Equipment on Deck

Gas Turbine Generators

Three units mounted on the aft trunk deck will generate all electrical power for the FSRU. Each turbine with its casing and air intake has a footprint area of approximately 50 x 8 ft (15 x 2.5 m). The maximum height above the deck at the air intake is approximately 33 ft (10 m).

Selective Catalytic Reduction (SCR)

The exhaust of each gas turbine is fitted with selective catalytic reduction (SCR) technology for air pollution control. Each SCR has a footprint of approximately 21 x 21 ft (6.5 x 6.5 m) and rises approximately 33 ft (10 m) above the trunk deck. From the SCR, the exhaust gas passes to a Waste Heat Recovery Unit (WHRU) whereby heat is recovered to the regasification heating system. Each WHRU has a footprint of approximately 72 x 16 ft (22 x 5 m) and rises approximately 65 ft (20 m) above the trunk deck.

Nitrogen Plant

This plant, which consists of air compressors and membrane nitrogen generating units, is described below. The plant is arranged on the starboard aft trunk deck and has a footprint of approximately 125 x 105 ft (38 x 32 m) and rises approximately 24 ft (7.5 m) from the trunk deck.

LNG Loading Arms

The fixed loading arms connect to the LNG carrier for receiving LNG to the FSRU. There are four arms mounted on the starboard side mishap of the FSRU. When stowed, they have a footprint of approximately 62 x 16 ft (19 x 5 m) and rise approximately 85 ft (26 m) above the upper deck or 55 ft (17 m) above the trunk deck level.

Recondenser

This regasification process component recondenses boil off gas (BOG) from the cargo tanks and nitrogen from the previously described nitrogen injection plant. It is located on the forward port side of the FSRU and is supported on a raised platform. It is approximately 15 ft (4.5 m) in diameter and rises 42 ft (13 m) above the trunk deck level.

Boil Off Gas Compressors

Three BOG compressors for NG vapor return to the LNG carrier and recondenser and for fuel gas supply to the process heaters are arranged in a separate house on the starboard trunk deck. The compressor house has a footprint of approximately 105 x 62 ft (32 x 19 m) and rises approximately 31 ft (9.5 m) above the trunk deck.

Shell and Tube Vaporizers

STVs are mounted on a raised platform on the port side of the trunk deck and forward of the recondenser. The vaporizers use a glycol/water mix heating medium to regasify the process LNG. LNG is supplied to eight STVs by eight individual vertically mounted and adjacent HP LNG pumps. Each STV is of approximately 6.5 ft (2 m) diameter and is approximately 55 ft (17 m) in length. The STVs extend approximately 15 ft (4.5 m) above the platform or 38 ft (11.5 m) above the trunk deck level. Each of the eight HP LNG pumps is of approximately 8 ft (2.5 m) diameter and rises 25 ft (7.6 m) above the trunk deck level.

Superheaters

Three superheater units are mounted on a raised platform 20 ft (6 m) above the trunk deck level) on the forward starboard side of the trunk deck. They are used to heat the vaporized gas to send-out temperature. Together, they have a combined footprint of approximately 52 x 10 ft (16 x 3 m) and extend only 7 ft (2 m) above the raised platform.

Metering and Odorization

This equipment is mounted on the raised platform adjacent to the superheaters and houses gas measurement flow meters and odorization for transfer to the subsea connecting pipeline. In total, the metering house has a footprint of approximately 50 x 75 ft (15 x 23 m) and extends approximately 7 ft (2 m) above the raised platform.

Cranes

Three utility cranes are fitted for general lifting service. One is located forward, having a radius of 95 ft (29 m) and a stowed height above the trunk deck of approximately 52 ft (16 m); two are located aft, each having a radius of approximately 124 ft (38 m) and 138 ft (42 m) and a height above the main deck of approximately 52 ft (16 m) and 85 ft (26 m), respectively.

Flare

The FSRU will be equipped with a flare for emergencies only. The flare provides for safe handling of vapors in the event there is overpressure in the storage system. The flare will rise approximately 197 ft (60 m) above the trunk deck.

2.1.3.1.3 Yoke Mooring System

The FSRU will be moored in place using a robust YMS that allows the FSRU to weathervane around the mooring jacket. The YMS is attached to the stationary tower structure, secured to the seafloor by four legs and is designed to withstand extreme storm events. The primary YMS design will safely accommodate the most severe weather data that can credibly occur in the area, including hurricanes. *See* Resource Report No. 11, Safety and Reliability, Section 11.3.4.1 for a more detailed description. The total area under the open design structure is about 13,180 ft^2 (1,225 m^2).

See Figures 2-6 and 2-7 for depictions of the YMS. The tower consists of the following components:

Jacket

The jacket is a four legged tubular steel structure attaching the tower to the seabed, each leg being of approximately 6.9 ft (2.1 m) diameter. Four corner piles will be installed to approximately 230 ft (70 m) into the seafloor. The corner piles will be installed in a

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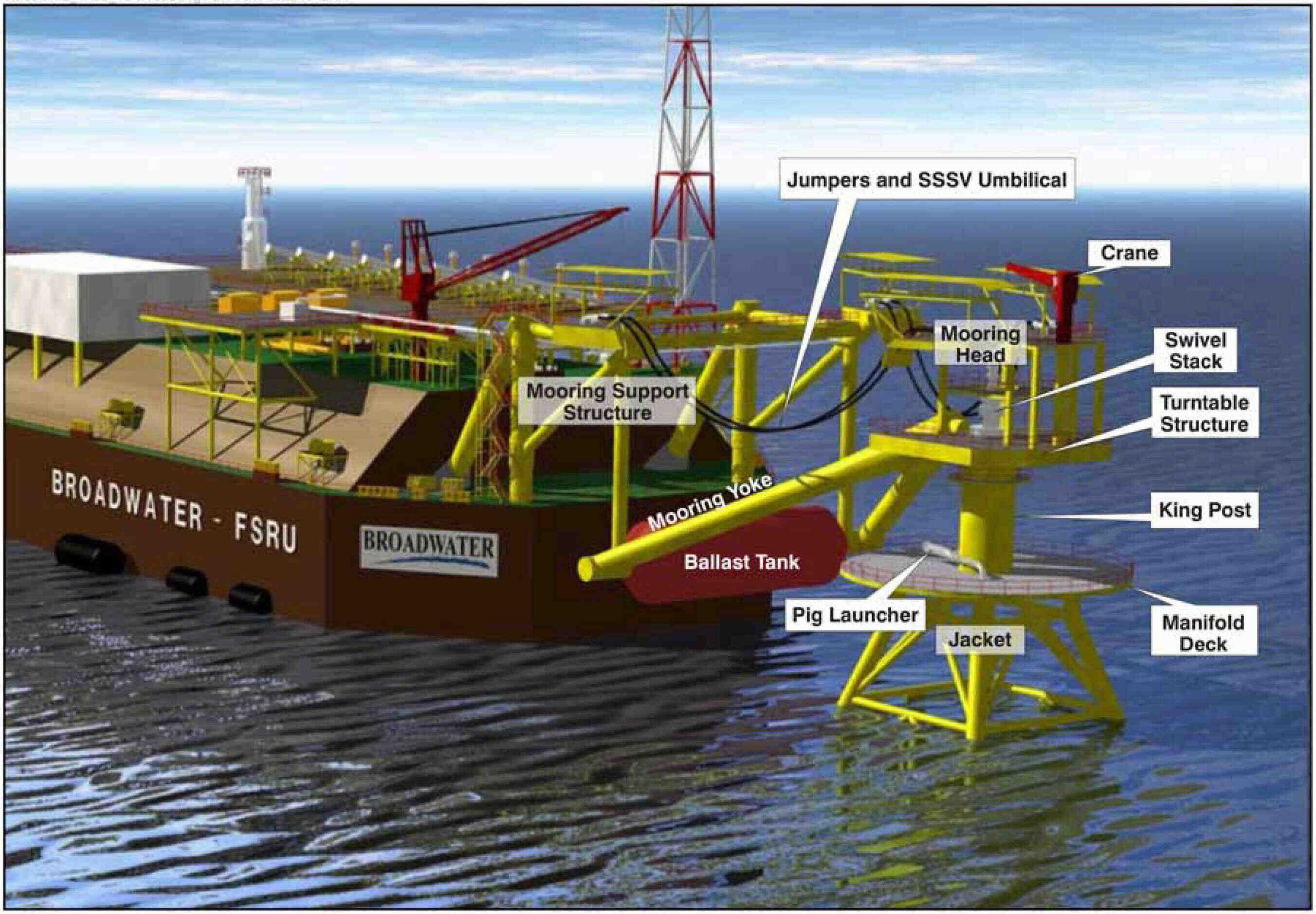

Figure 2-6 Detailed Depiction of Yoke Mooring System

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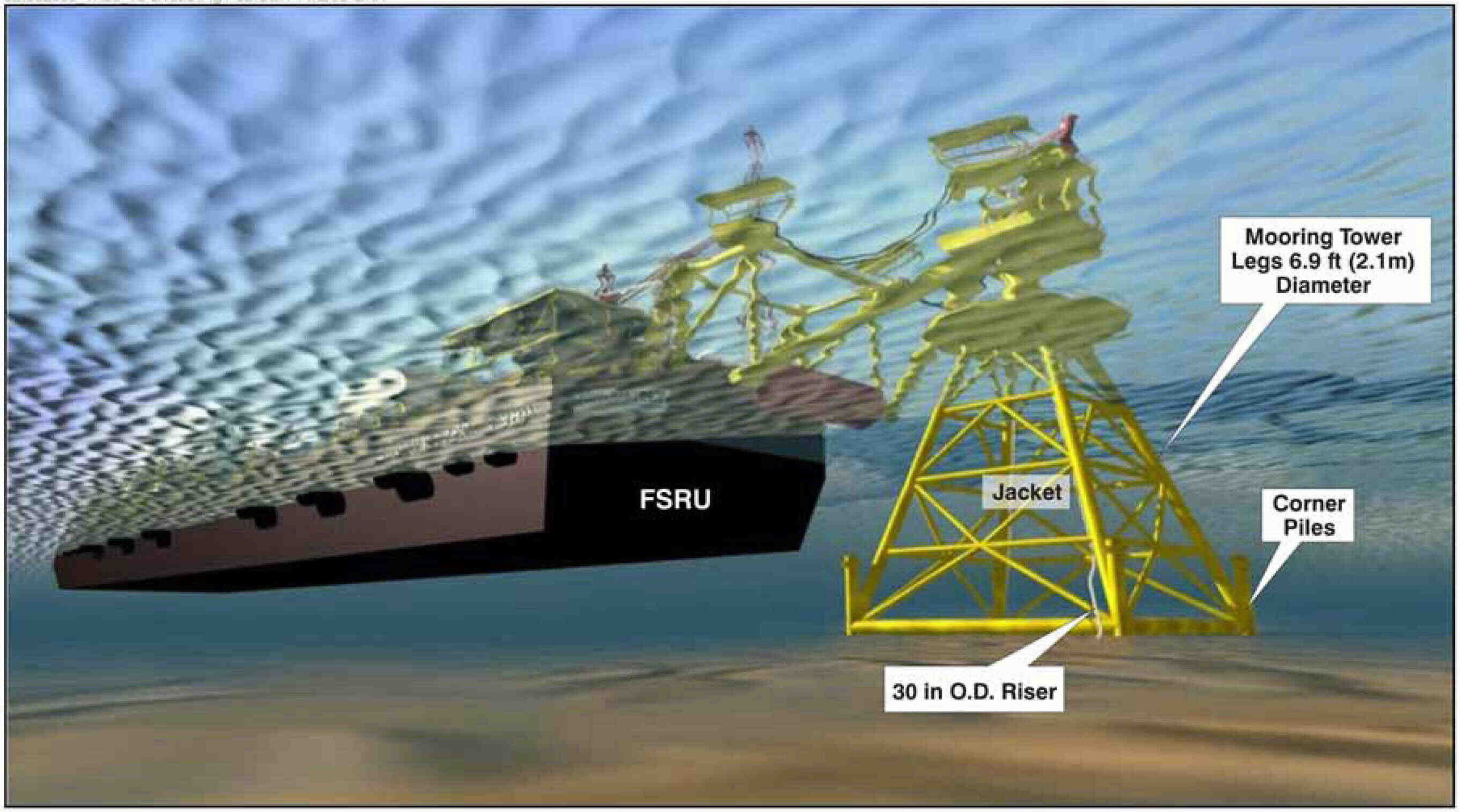

Figure 2-7 Subsea Depiction of YMS Jacket and FSRU

square of approximately 115 ft (35 m) to a side. The jacket will be attached to the piles and welded and grouted in place. Located within the jacket is the pipeline riser that connects to the remainder of the pipeline on the sea floor. The pipeline riser will be secured to the insides jacket legs by bolted clamps to provide protection against any waterborne impacts.

Mooring Head

The mooring head is located atop the jacket and supports the pipe work and equipment. The total height of the structure above the sea bed is approximately 223 ft (68 m) of which approximately 134 ft (41 m) will be above sea level. The mooring head at the upper most part is approximately 55 ft (17 m) in width. The YMS is connected to the mooring support structure (MSS) on the FSRU via a yoke of approximately 131 ft (40 m) in width, and the YMS kingpost centerline will stand approximately 164 ft (50 m) forward of the FSRU bow.

Yoke

The yoke is a tubular, triangular frame that is connected to the mooring head via a roll-and-pitch articulation and incorporates a counter weight. The mooring yoke is a tubular steel triangular frame with the apex connected to the turntable. The structure has roll and pitch articulation at its apex, and a tubular ballast compartment connecting the opposite ends of the two side members. The ballast tank remains empty until it is lifted and connected to the two mooring arms so it weighs less during lifting/connecting operations, and so it floats prior to the FSRU arrival.

Once hooked up to the FSRU, the yoke ballast compartments will be filled with 1,984 short tons (1,800 tonnes) of fresh or distilled water, which will have been treated with a benign proprietary corrosion inhibitor so as to prevent any internal corrosion of the ballast space. This ballast water acts as counterweight to help restore the FSRU to equilibrium should it move under environmental effects. Although not anticipated, if any inhibited water must be drained, it shall be collected and disposed of at a suitable onshore facility.

Access to and from the FSRU to the mooring tower is via the yoke through a retractable gangway, ladders attached to the mooring arms, and a series of platforms and ladders installed on the yoke structure.

Mooring Support Structure (MSS) on FSRU

The MSS on the FSRU consists of a tubular frame mounted onto the bow of the FSRU. The structure overhangs the bow of the vessel to provide clearance for the yoke. The MSS mounted on the FSRU’s bow consists of a tubular steel space frame structure, which is welded into reinforced areas in the vessel’s bow. The structure overhangs the bow of the FSRU to ensure clearance between the mooring yoke and the FSRU during the worst design condition displacements. The two mooring legs that support the ballasted end of the mooring yoke are suspended from the upper outermost edge of the structure via uni-joints.

The MSS is designed not only to support the two mooring legs, but also to act as a tie-in point for the send-out gas flexibles, utility transfer hoses, and umbilicals spanning from the mooring tower. Access to the yoke via a stairway up from the FSRU deck and ladders attached to the mooring legs is also provided by the MSS. Reinforced lift attachment points and lugs are provided on the MSS to facilitate the lift and connection of the yoke to the mooring legs during installation of the FSRU when it arrives on site.

Jumpers

The transfer of the send-out gas between the FSRU and the yoke is achieved through two 16-in (405-mm) inside diameter, 54.5-ft (16.6-m) -long jumpers that are suspended between the MSS on the FSRU and the turntable structure on the fixed mooring tower. The jumpers have a wall thickness of 2.2 in (56 mm) and are composed of stripwound stainless steel, rubberized textile plies with steel cable reinforcement, and an elastomer external coating. The means of connection between transfer lines and the pipeline riser is described in detail in Resource Report No. 13 (Engineering and Design Material).

2.1.3.1.4 LNG Storage and Vaporization Facilities

LNG Containment

The FSRU will temporarily store LNG in membrane storage tanks incorporated into the hull of the structure with a total net storage capacity of 350,000 m^3 (approximately 8 billion cubic feet [bcf] of natural gas). The storage capacity of the FSRU will be divided between 8 LNG tanks, each having an approximate volume of 44,850 m^3. The stored LNG will be maintained at a temperature of minus 260 °F and a normal operating pressure of 1 to 3 pounds per square inch (psi), closely approximating atmospheric pressure. Each LNG storage tank will be equipped with a retractable pump that will be used to transfer LNG from storage to the vaporizer system. No mechanical means of refrigeration will be required because LNG is refrigerated (liquefied) at the sending site and transported in thermally insulated LNG carrier cargo tanks.

Using the Gaz Transport and Techigaz Mark III membrane tank system as an example, the main components of the containment system will include:

- A 1.2-mm-thick stainless steel primary barrier, consisting of an orthogonal system of corrugations to compensate for thermal contraction and mechanical ship deflections;

- Insulation, consisting of rigid polyurethane foam with reinforcing glass fibers between two plywood sheets, the thickness of which is determined to limit the boil off rate to 0.15% per day with cargo tanks at 98% full; and

- A secondary barrier, comprised of laminated composite material made of two glass cloths with aluminum foil (called Triplex) in between, for tightness. The secondary barrier, provided to contain LNG in case of leakage through the primary barrier, is inserted in the insulating structure.

The membrane and insulation system transmits cargo pressure to the inner steel hull structure of the FSRU.

The Gaz Transport and Techigaz No. 96 membrane tank system may be used as an alternative to the Gaz Transport and Techigaz Mark III.

All materials, material testing, and approval of manufacturers for the LNG containment system will be accordance with the requirement the Classification Society standards. All materials will be suitable for the specified temperatures. The material used for construction of the membrane primary barrier will be chromium nickel stainless steel with very low carbon content.

Vapor Handling System

During normal operations, a small amount of the LNG within the storage tanks will vaporize, primarily due to heat inputs from the ambient conditions, in-tank pumps, and changes in barometric pressure. Vapor will also be generated during LNG carrier unloading due to the displacement of tank vapors as the tanks are filled with LNG.

A vapor-handling system will collect and transfer BOG originating from the storage tanks either back to the LNG carrier or to a recondenser, which is used to re-liquefy all of the BOG.

During LNG carrier unloading operations, a proportion of the BOG will be returned to the ship via dedicated BOG compressors to compensate for the volume of liquid pumped out to maintain the carrier's tank pressure.

Any generated BOG that is not returned to the carrier, or BOG that is normally generated when no FSRU loading operations are taking place, will be sent by the compressors to the recondenser, where it will be condensed back into liquid by direct contact with LNG. The recondensed BOG is then combined with the send-out LNG prior to being pumped up to pipeline pressure in the send-out pumps and passing through the vaporizers. The FSRU will have three BOG compressors, two operational and one installed as a spare.

The BOG compressors act as a pump for BOG for its delivery to either the LNG carrier or the recondenser. The recondenser is a vertical chamber that allows vapor and system LNG to come into direct contact, such that the gas is condensed by the LNG back into the liquid stream.

LNG Vaporization System

The LNG from the LNG cargo tanks on the FSRU will be pumped from the tanks through individual in-tank pumps.

The LNG from the cargo tanks passes through a recondenser where BOG is introduced and re-liquefied. On exiting the recondenser, the LNG passes to a manifold where it is divided into a number of regasification trains each comprised of a high-pressure pump and vaporizer. The pumps raise the LNG pressure to that suitable for entry to the vaporizers. The regasification plant is designed to vaporize LNG at a peak capacity of 2,500 m^3/hour.

The FSRU will have eight STVs that will vaporize LNG to natural gas. From there, the vaporized gas is further heated to up to 144 °F (62°C) in the printed circuit heat exchanger (PCHE) type superheaters, with send-out gas temperature being dependent on gas delivery requirements. The gas will then pass through a metering station prior to being routed to the transfer hoses of the mooring system and finally to the subsea connecting pipeline via the riser. Odorant will be added on the FSRU prior to injection into the subsea connecting pipeline.

Both the vaporizers and the superheaters use a closed loop, 50/50 glycol/water mix as a heating medium (supplied at a temperature between 162°F [72°C] and 185°F [85°C]). The primary heat source for the glycol/water system will be supplied by gas-fired process heaters and augmented by exhaust heat from the WHRUs of the gas turbines. There is no use of, or discharge to, seawater from the proposed vaporizer system. The fuel source for the process heaters will be vaporized LNG tapped from the vaporizer system. The process heaters will consume approximately 6 million cubic feet per day (mmcfd) of natural gas at 100% load level.

The process heaters will be equipped with SCR units to reduce the nitrogen oxides (NO_x) content of the exhaust gases down to 2.5 parts per million (ppm) to meet the region's strict NO_x control requirements. An SCR unit operates by continuously injecting a small amount of aqueous ammonia into the process heater exhaust stream and then passing the exhaust gases through a catalyst. The ammonia is needed to make the chemical reaction in the catalyst be as effective as possible in reducing NO_X. Volatile organic compounds (VOCs) and carbon monoxide (CO) content will also be reduced to 10 ppm or less by use of special catalysts. These special catalysts do not require anything to be added to the exhaust to reduce VOC and CO emissions.

The delivery, storage and handling of aqueous ammonia will be addressed at the detailed design stage. Equipment and procedures will conform to Class and manufacturers' requirements, including Material Safety Data Sheets.

Diesel Oil

Other than LNG as a fuel source, diesel oil is the only liquid fuel to be stored onboard. This will be used for:

- Gas turbine (commissioning and back only);
- Diesel alternators (including emergency unit);
- Diesel engine driven fire pumps; and
- Lifeboat engines.

All fuel (and lubricating oil) tanks will be of welded steel construction integrated into the hull and well secured. The main tanks are as follows:

- Diesel oil storage tank: two x 1,175 m^3;
- Diesel oil service tank: two x 25 m^3; and
- Emergency generator diesel oil tank: one x 8 m^3.

Other small oil tanks sizing and storage locations will be defined at the detailed design stage, including storage of small packaged drums.

All fuel and lubricating oil tanks and systems will be fitted with safety and spill containment features according to Class requirements and this will be further defined at the detailed design stage. Safety and spill features will include:

- Drip pans or coamings, where appropriate;
- Quick closing, remotely operated tank isolating valves; and
- Heat-resistant level gauges/alarms.

Oil handling procedures will be developed within the FSRU Safety Management Systems and conform to United States Coast Guard (USCG) Oil Transfer Procedures.

Nitrogen Injection

In order to meet gas quality limits of the existing IGTS tariff, nitrogen will be injected into the regasified LNG, up to a maximum of 4% by volume, as may be required. Nitrogen injection facilities will be located on the FSRU and will utilize membrane technology to produce the required nitrogen from the ambient air.

2.1.3.1.5 Berthing and Unloading Facilities/LNG Receiving Facilities

The berthing and unloading facilities at the FSRU, comprised of liquid/vapor loading arms, will include a single LNG carrier berth located midship on the starboard side of the FSRU. The berth can accommodate one LNG carrier with a capacity in the range of 125,000 up to a potential future capacity of 250,000 m^3 at a time.

The offloading area of the FSRU will support all equipment needed to safely off-load LNG from the LNG carrier and will consist of:

- Four LNG loading arms;
- Loading arm power packs and controls;
- All necessary piping and manifolds;
- Gas and fire detection, fire protection, and firefighting facilities;
- Life-saving equipment;
- Provisions for telecommunications;
- Ship/shore access gangway;
- Small crane; and
- Cold splash protection.

LNG transfer from the LNG carrier to the FSRU is achieved via dedicated unloading arms as are standard for onshore terminals. The four unloading arms comprise two liquid lines, one vapor return line, and one spare liquid/vapor line. Each arm has a capacity of 5,000 m^3/hr liquid or 15,000 m^3/hr vapor using 16-inch standard arms with quick disconnect coupling, a powered emergency release coupler, and a manifold guidance system. Loading arm safety is integrated into the emergency shutdown (ESD) system.

The FSRU and LNG carrier manifold and loading arms will be of suitable material for LNG handling (e.g., stainless steel SS316L or similar) and will be further defined at the detailed design stage.

2.1.3.1.6 Power Generation

Gas Turbines

Broadwater proposes to install three 22-megawatt (MW) aero-derivative, coupled generator sets, with one unit serving as a spare. The primary fuel for the gas turbines will be natural gas (supplied from and reduced in pressure from final process send-out). One of the turbines will be designed to use a secondary fuel (low-sulfur diesel oil with full liquid fuel conditioning) and filtration system incorporated for use in emergency situations.

A horizontal WHRU will be attached to the exhaust end of each of the gas turbines to provide heat to the LNG superheaters and to the ancillary heating water system. Turbine exhaust gas will pass through a CO catalyst to reduce CO to 10 ppm or less and then through a heat medium (glycol-water) tube bundle.

As with the process heaters, the gas turbines will be equipped with SCR units to reduce the NO_X content of the exhaust gases down to 2.5 ppm or less in order to meet the region's strict NO_X control requirements. The SCR units will be located after the primary heat exchange bundle. A second heat exchange bundle is located downstream of the NO_X reduction catalyst bed to recover most of the remaining heat in the exhaust stream.

Diesel Engines

There will be three diesel generators, all above the upper deck. One of these generators will be a self-contained and suitably sized emergency diesel generator for black start/first start operations.

2.1.3.1.7 Seawater Withdrawal and Discharge Systems

The FSRU will have four seawater intakes comprised of two main intakes located on the port and starboard sides of the bottom of the FSRU hull, and two fire pump intakes located on the fore and aft of the bottom of the FSRU hull.

Sea chest intakes will withdraw water from an approximate depth of 40 feet (12 m). The sea chest intakes will have a coarse grate (grate size approximately 4 inches x 2 inches) at the interface between the seawater and the FSRU hull. Intake velocities will be limited to 0.5 feet/second (0.15 m/s), which will allow motile organisms to easily swim away from the intakes.

The port and starboard sea chests will be connected by an approximately 35-inch crossover pipe. Only one intake will operate at any given time.

The main seawater intakes will supply water for:

- Ballast: ballast intake and discharge will be based on the volume of LNG being received by the FSRU and/or being revaporized and sent out by the FSRU;

- Desalination plant (reverse osmosis unit): two pumps will be available, with only one pump in operation at any time;

- Marine growth prevention system;

- Bilge and general service pumps: to provide a water curtain for the LNG loading area;

- Inert gas scrubber cooling pump: for infrequent use only if cargo tank inerting and aerating is required; and

- Sea water cooling pump: for emergency use only if the glycol-water system fails.

In the sea chest, sodium hypochlorite is added at a continuous low dose of 0.2 ppm, resulting in a residual chlorine concentration of 0.01 to 0.05 in the seawater used by the FSRU. Sodium hypochlorite is produced from the intake sea water via an electro-chlorination unit which, by passing an electric current through the side steam seawater via two concentric titanium electrode tubes, converts the sodium chloride in the seawater to safe, low concentration sodium hypochlorite, which is re-injected into the sea chest. Water is treated in this way to prevent marine growth on the FSRU seawater systems.

After treatment with sodium hypochlorite, water will pass through an in-line 5-mm screen to a manifold where the water is directed for various use throughout the FSRU.

The quantities of water withdrawals and discharges associated with the FSRU are provided in Resource Report No. 2 (Water Use and Quality).

Water ingested by either of the two fire water intakes will not be treated with sodium hypochlorite.

Ballast System

The FSRU will be equipped to maintain its draft, trim, and stability within a specific range by using a water ballast system. The port and starboard sea chests will provide the seawater for the ballast system.

Normal ballast water intake will occur in conjunction with the continual send-out of natural gas through the marine pipeline. Given that the density of LNG relative to sea water is approximately 0.45, to offset a daily vaporization and send-out of 2,000 m^3/hour, the FSRU will need to take on approximately 900 m^3/hr of seawater, or approximately 5.7 million gallons of water per day.

During LNG offloading from the carrier to the FSRU, the FSRU will need to discharge additional volumes of ballast water to offset the LNG transferred to the FSRU. During the course of the loading activities, discharge of ballast water will be as high as 4,500 m^3/hr to balance a loading rate of 10,000 m^3/hr. Total ballast water released from the FSRU will equal approximately slightly less than one half of the cargo volume offloaded. Therefore, for a 145,000 m^3 LNG shipment, the FSRU would discharge approximately 65,250 m^3 (approximately 17.2 million gallons) of ballast water.

The FSRU will be ballasted at the construction yard before commencing the tow to Long Island Sound. In compliance with the International Convention for the Control and Management of Ships Ballast Water and Sediments, a ballast water exchange will be completed during the voyage. Regulations require this to be conducted at least 200 nautical miles from the nearest land and in water at least 200 meters in depth, with an efficiency of 95% volumetric exchange of ballast water.

The International Convention is set forth in 33 Code of Federal Regulations (CFR) Subpart D - Ballast Water Management for Control of Nonindigenous Species in Waters of the United States.

Waste and Water Treatment

Operations on the FSRU will generate various types of waste material. Hazardous materials that will be onboard the FSRU include paints, solvents, ammonia, and odorant. In addition, lubricating oil will be stored onboard for use with various rotating equipment. Diesel fuel will also be onboard for the emergency diesel generator. Additional discussions of the primary waste types are presented below.

Paints and Solvents

FSRU maintenance activities will require the use of various paints, solvents, and other materials. These materials will be brought onboard in retail-sized containers and stored in compartments specifically designed and constructed for storage of hazardous materials and paints. Empty containers will be brought to shore for appropriate disposal or recycling.

Gray and Black Water

The FSRU will be equipped with an onboard treatment plant to treat all sewage and gray water generated onboard. If treatment plant options cannot meet the State of New York discharge requirements, all black water will be routed to a holding tank in the FSRU and shipped to shore for disposal at an approved facility. Any gray water generated by systems on the FSRU such as sinks, shower drains, and floor drains that may contain increased levels of detergents and nutrients would also be routed to a holding tank and shipped to shore for disposal at an approved facility.

For the onboard treatment plant, Broadwater will use a marine bioreactor (MBR) rather than a typical USCG treatment system. The discharge from the MBR, which will be located approximately 3 feet (1 m) below the water line, is anticipated to be approximately 2,000 to 5,000 gallons per day (8 to 19 m^3/d). The MBR provides an advanced treatment process that produces a discharge of much higher quality than a USCG treatment device, and provides Broadwater with the ability to be consistent with the Long Island Sound Comprehensive Conservation and Management Plan.

A typical USCG treatment device can achieve the following effluent quality standards:

- Suspended solids: 150 mg/L; and
- Fecal coliform: 200 counts/100 mL.

Biological oxygen demand, pH, and chlorine are not parameters typically analyzed for treatment in this type of system.

The MBR system produces a much higher effluent quality and addresses more water quality parameters than a USCG treatment device. The MBR effluent quality standards include:

- Suspended solids: 3.1 mg/L;
- Biological oxygen demand: 2.6 mg/L;
- Fecal coliform: 10.6 counts/100mL;
- pH within acceptable limits for the original water source; and
- Chlorine: 0 µg/L.

Aqueous Ammonia

Selective catalytic reduction (SCR) will be used to reduce air emissions of NO_X to levels in accordance with New York State requirements for Suffolk County. Aqueous ammonia will be used as part of the SCR process. Aqueous ammonia storage and handling procedures will be developed when the detailed FSRU design commences.

Odorant (Mercaptan)

Odorant is added to natural gas to give it a perceptible odor, even at low concentrations. Storage and handling procedures as well as the amount and type of odorant injected into the gas stream will be in accordance with regulatory requirements.

Only commercially available odorant will be used, and handling will be in accordance with the manufacturer's recommendations and the appropriate Material Safety Data Sheet. For logistical purposes, it is anticipated that International Standards Organization (ISO) tank containers will be used to transport and store the odorant onboard the FSRU. These containers typically have a capacity of 6,600 gallons (25,000 liters), and deck space will be provided on the FSRU for two containers with an appropriate spill containment arrangement around this area. For safety purposes, as the container is being emptied, the vapor space will be inerted from the FSRU nitrogen supply. Odorant spill procedures will be included within the terminal Spill Response Planning and Preparedness Plan for both transport and storage phases.

2.1.3.1.8 Drainage Systems and Deck Runoff

Broadwater will manage storm water runoff from atmospheric precipitation depending on the location on the FSRU. Uncontaminated storm water runoff from the FSRU will be comprised of rainwater and will be directed overboard via scupper drains. The volume of this runoff is dependent on the local level of precipitation and will be at ambient temperature when drained to the Sound. Runoff from any deck location that has the potential for oil and/or grease contamination will not be directed overboard. Runoff from these areas will instead be collected and routed to the bilge holding tank for shipment to shore for disposal at an approved facility. These practices ensure that storm water runoff does not contain hydrocarbon contaminants from the FSRU. Discharge during testing of the fire water bypass system will be overboard via scupper drains.

2.1.3.1.9 Other Facilities

Crew Quarters

The FSRU will have facilities to accommodate a permanent crew of up to 30 and a temporary crew of 30. For safety reasons, all living, dining, and recreational areas will be contained within the crew quarters to separate the processing area from the Accommodation Area.

Command and Control Facilities

Command and control facilities, including monitoring and control facilities for natural gas process activities, ballasting, communication, radar equipment, electrical generation, emergency systems, and thruster controls, will be located in a central control room in the Accommodation Area.

2.1.3.1.10 Safety Systems

Emergency Shutdown Systems

The FSRU will have emergency shutdown (ESD) systems to allow for the safe termination of operations in the event of an operational problem. The systems will allow for either the shutdown of individual sections of the FSRU or the entire facility, depending on the particular event.

The LNG carrier and the FSRU will each be equipped with their own ESD systems, which will be inter-connected in such a way that any unusual action on the FSRU or the carrier will automatically stop the unloading procedure onboard the ship. Details of the specific ESD systems with which the FSRU will be equipped are described in Resource Report No. 13 (Engineering and Design Material).

LNG Spill Drainage and Containment

To protect the hull of the FSRU from any LNG spill that may occur, coaming and draining systems will be provided to divert spilled LNG to a disposal point on the port side of the FSRU. The disposal point will be selected such that there would be no interference with any other vessel that may be in the immediate vicinity of the FSRU. LNG spills from loading arms are also mitigated using stainless steel cladding on parts of the FSRU hull at loading points, combined with a water-curtain spray. The LNG will leave no residue and will not have an impact on water quality. Resource Report No. 13 (Engineering and Design Material) Section 13.4 contains LNG spill details.

Fire Prevention

Fire prevention will be incorporated into the design and operation of the FSRU. All equipment and operations and maintenance procedures will be designed and developed to minimize the consequences of accidentally releasing flammable liquids or gases. The FSRU will be fully equipped with smoke and fire detection systems and a fire-fighting water system.

A separate fire-fighting (deluge) spray water system to cover the process area, crew accommodations, and lifeboats will be provided in accordance with USCG requirements. Additional details regarding fire protection systems and the Fire and Explosion Analysis are provided in Resource Report No. 13 (Engineering and Design Material).

2.1.3.1.11 LNG Carriers

LNG carriers will call at the Broadwater FSRU at a frequency of up to three times per week, depending on carrier size. LNG carriers usually retain a small amount of ballast during the loaded voyage for trim purposes. It is very unlikely that vessels will discharge any of this ballast within Long Island Sound, but in any event the water would be subject to a Ballast Management Plan, as required by international regulations.

During offloading, the LNG carrier takes on ballast water through a dedicated ballast system to maintain trim, stability, and limit hull stresses. The water intake locations differ from vessel to vessel, but typically are within the machinery space and either on the bottom of the hull or towards the bottom of the side-shell in the vicinity of the turn of the bilge. Intake systems are of similar design to the FSRU. With an LNG discharge rate of 10,000 m^3/hr, the LNG carrier will need to take on ballast water to maintain trim, although an LNG carrier will typically leave the FSRU at a reduced draft (i.e., with higher freeboard) than when it arrived. The total amount of ballast taken on will vary according to the ship size and the anticipated weather conditions that may be encountered on departure. A 145,000 m^3 LNG carrier typically requires approximately 50,000 m^3 (13.2 million gallons), and a future design 250,000 m^3 carrier is estimated to require approximately 97,000 m^3 (25.6 million gallons) of water to proceed on a voyage.

To maintain the hull integrity of the FSRU and the LNG carrier, a constant curtain of water will be directed overboard during LNG transfer from the carrier to the FSRU. Water curtain volumes will be about the same as for the FSRU; 8,718 gallons/hour (33 m^3 per hour) during the cargo transfer time. This is standard industry practice. To prevent the growth of marine organisms, the water will likely be treated with sodium hypochlorite to the same concentration as the intake water for the FSRU.

2.1.3.2 Subsea Connecting Pipeline

2.1.3.2.1 Overview of Pipeline

The Project will include an approximately 21.7–mile-long, 30-inch outside diameter subsea gas transmission pipeline from the FSRU to a subsea hot tap interconnection on the existing IGTS pipeline crossing of Long Island Sound. Figures 2-8 and 2-9 show the alignment and profile of the proposed pipeline route. Features of the pipeline route are summarized in Table 2-1.

Table 2-1 Subsea Connecting Pipeline Route Features

Location	Description	Water Depth
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]

2.1.3.2.2 Design Codes and Standards

The pipeline system will be designed in accordance with Part 192, Title 49, "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards" (latest edition) of the CFR. Provided all minimum federal safety standards have been met, ASME B31.8 "Gas Transmission and Distribution Piping Systems" will be used to supplement the requirements of 49 CFR, Part 192. Codes from the following organizations are incorporated into the design as applicable:

- American Gas Association (AGA)
- American National Standards Institute (ANSI)
- American Petroleum Institute (API)
- American Society of Mechanical Engineers (ASME)

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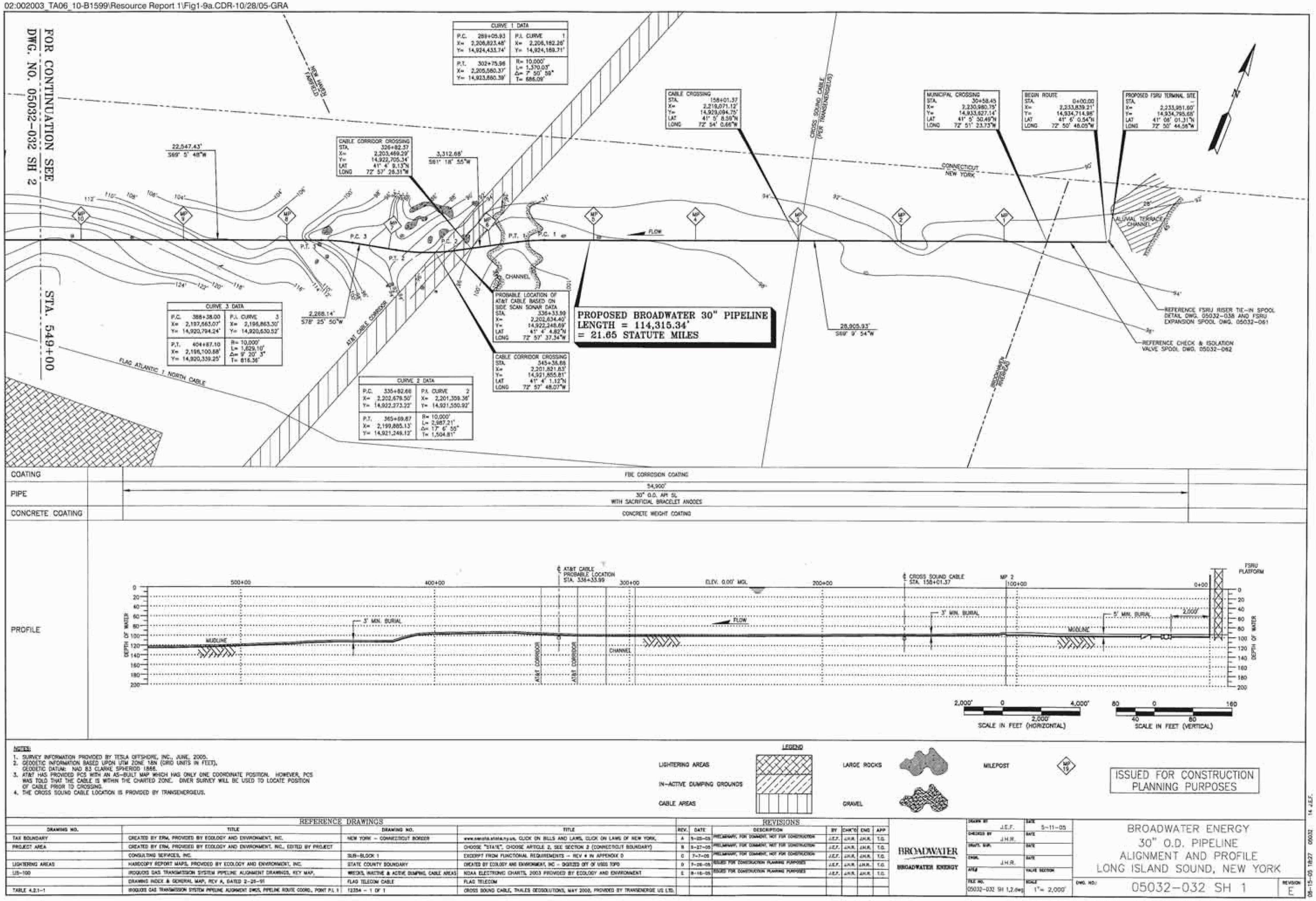


Figure 2-8 Subsea Connecting Pipeline Alignment and Profile Drawing, Part 1

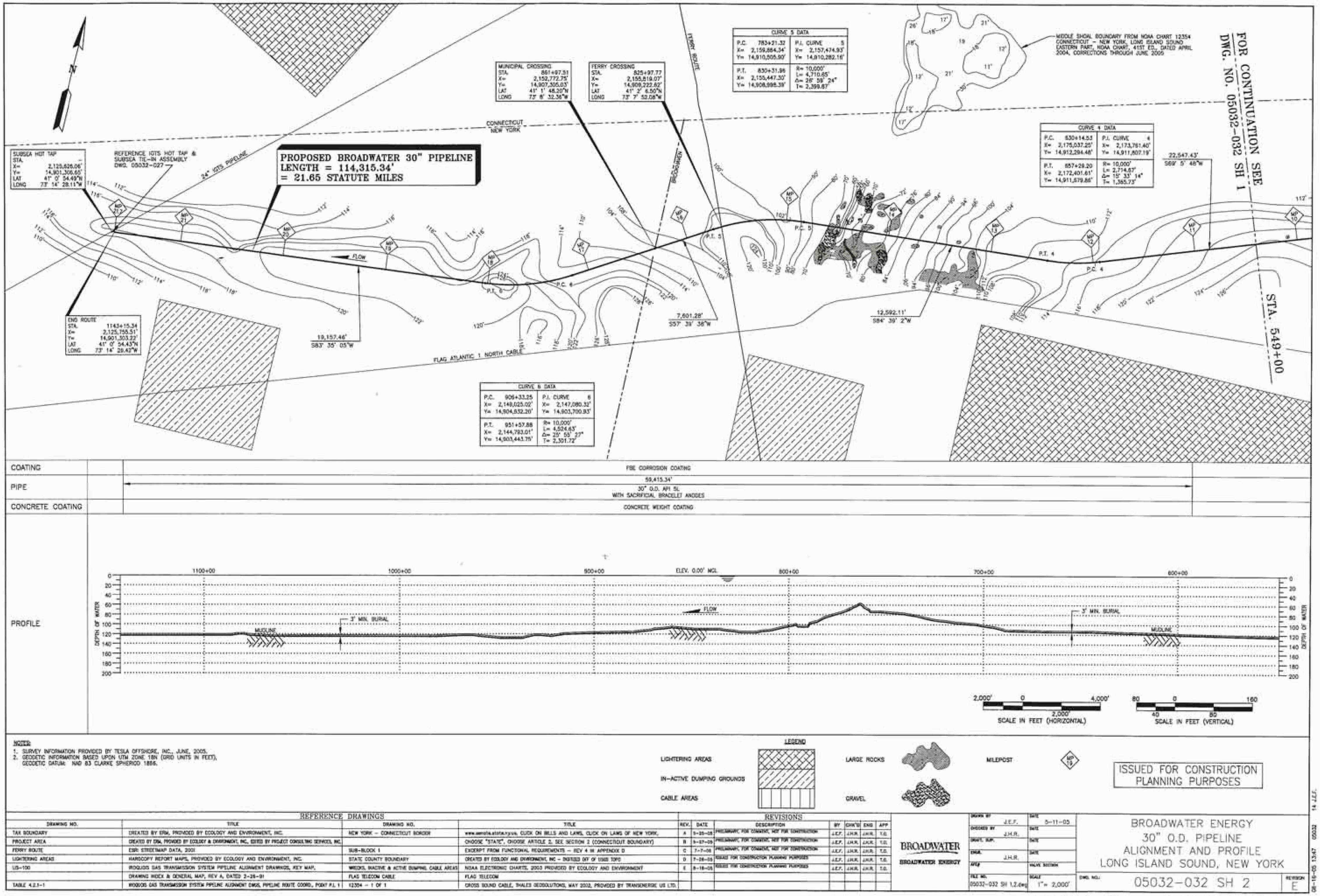


Figure 2-9 Subsea Connecting Pipeline Alignment and Profile Drawing, Part 2

- Instrument Society of America (ISA)
- International Standards Organization (ISO)
- Manufacturers Standardization Society of the Valve and Fitting Industry (MSS)
- National Association of Corrosion Engineers (NACE)
- Occupational Safety and Health Administration (OSHA)
- Uniform Building Code (UBC)

2.1.3.2.3 Pipeline Material Specifications

The pipeline is in a Class 1 Location as defined by 49 CFR Part 192. The pipeline material will be high strength steel manufactured in accordance with the latest edition of API 5L Standard Specification for Line Pipe. The wall thickness of the 30-inch-diameter pipeline will be designed to resist the combined loads that may be experienced during pipeline installation, testing, and normal operation. Limitations imposed by regulatory requirements and design codes also will be accounted for in the pipeline design. The pipeline will be designed for a maximum allowable operating pressure (MAOP) of 1,440 psig. Pipeline fittings will conform to ANSI 900 specifications, and the line pipe will be of one of the following or comparable material specifications:

- 30" O.D. x 0.720" W.T. API 5L Gr. X60; or
- 30" O.D. x 0.665" W.T. API 5L Gr. X65; or
- 30" O.D. x 0.618" W.T. API 5L Gr. X70.

2.1.3.2.4 Corrosion Protection

To resist corrosion of the pipeline exterior, the pipeline will be externally coated with a coating material such as fusion-bonded epoxy.

In addition to an external coating, the pipeline will incorporate sacrificial anodes with a design life of a minimum of 30 years. This secondary cathodic protection system will supplement the pipeline coating should it be damaged during installation or operation. An insulating joint will be installed in the IGTS spool piping to isolate the IGTS pipeline cathodic protection from the Broadwater pipeline cathodic protection. Also an above water isolation flange kit will be considered in the riser and topside design of the YMS.

2.1.3.2.5 Concrete Weight Coating

Weight coating required for negative buoyancy and on-bottom stability will be steel reinforced concrete (140 to 205 pounds per cubic foot densities, as required) applied over the fusion-bonded epoxy (FBE) corrosion coating. During the detail design phase the concrete coating thicknesses will be determined through an on bottom stability analysis, and the use of adhesive between FBE coating and concrete weight coating for additional adhesion during lay operations will be evaluated. Preliminarily the thickness of the concrete weight coating is approximately 3 inches.

The concrete weight coating will be applied at an existing off-site concrete coating plant at a location to be determined during detailed design. The concrete weight coated line pipe will then be transported to the region to a stockpile and transhipment site where it will be stored awaiting commencement of construction.

2.1.3.2.6 Pipeline Emergency Shutdown and Isolation Systems

The pipeline will connect the FSRU to the IGTS pipeline and will include a number of valves that are required for isolation and installation. On the YMS mooring tower an ESD and isolation valve will be provided upstream of the pipeline riser. The balance of the ESD and isolation systems on the pipeline will be comprised of various valves packaged into pipeline spools that will be fabricated off site and installed by the pipeline contractor.

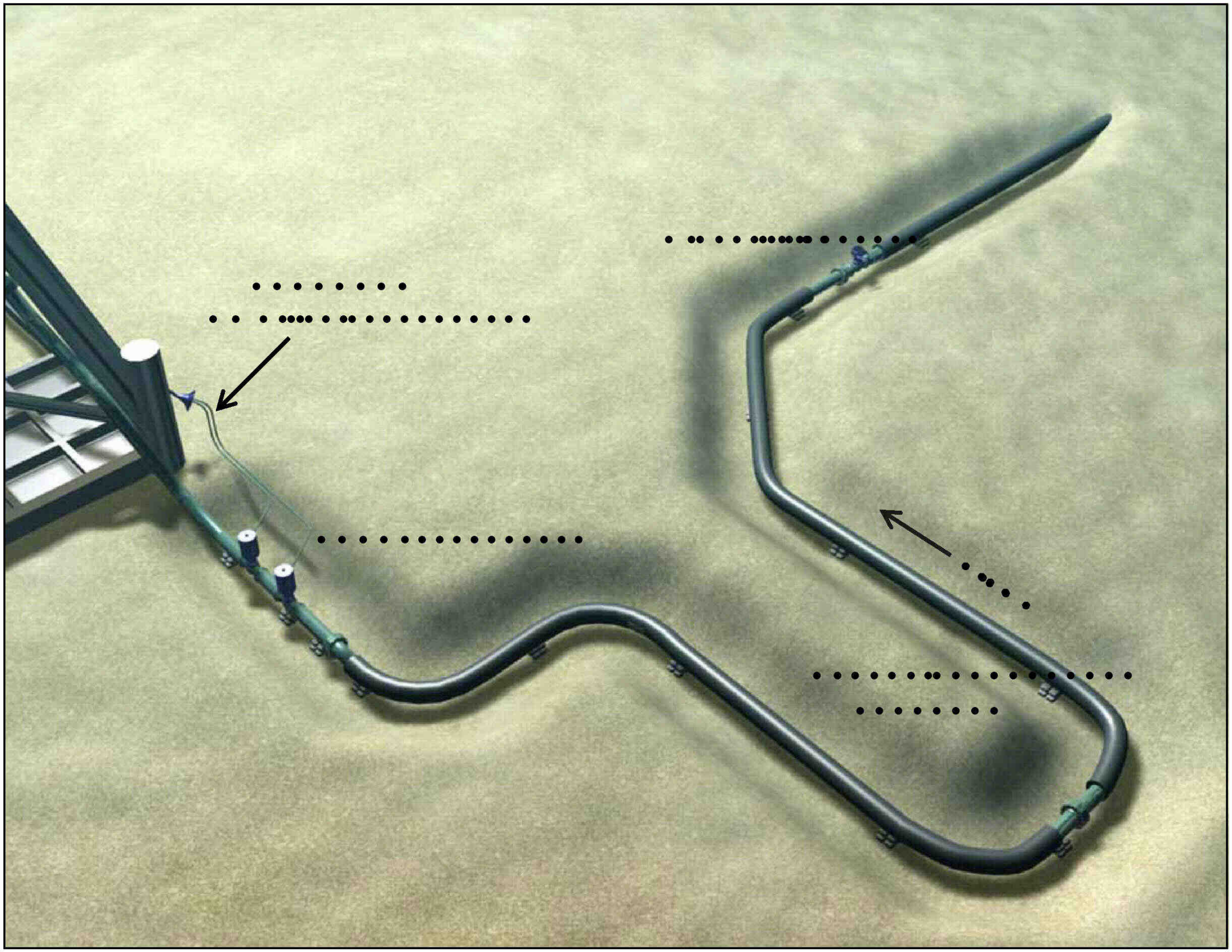
The subsea connection between the Broadwater pipeline and the 30-inch-diameter riser on the YMS is depicted on Figure 2-10. The subsea tie-in is shown in schematic form on Figure 2-11a, and associated excavation volumes are indicated on Figure 2-11b. The connection will consist of four spools, of which two will provide an approximately 80 ft x 40 ft expansion loop, and the following two will comprise the subsea shutdown and isolation systems at the pipeline begin-of-line:

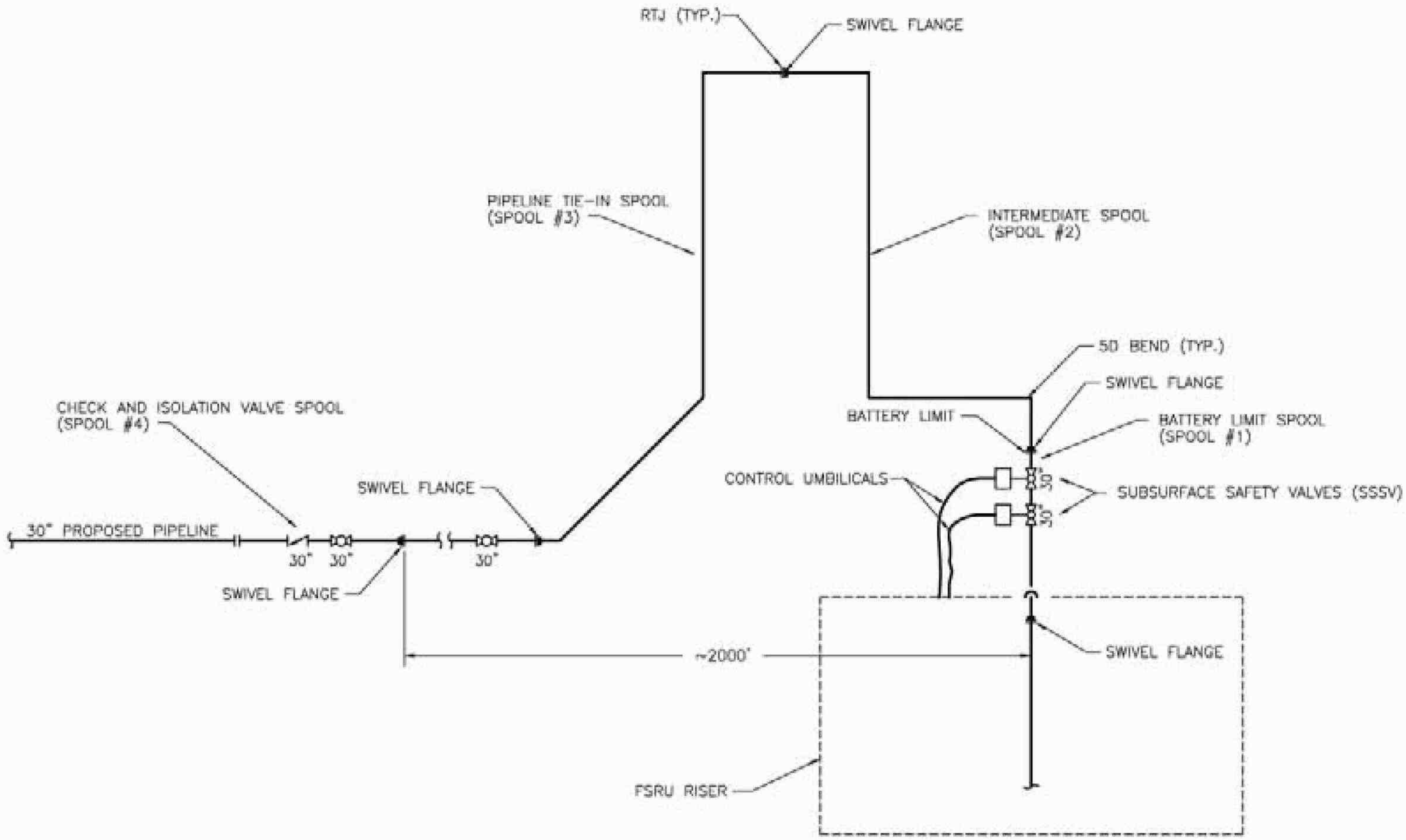
- SSSV and umbilical: The battery limit spool incorporates a Subsea-Subsurface Safety Valve (SSSV). The SSSV will be a 30-inch full-opening ball valve fitted with an actuator and an umbilical connection. The SSSV will be controllable from the YMS and from the FSRU for remote, automatic, and ESD activation.

- Block valve: The pipeline tie-in spool incorporates a gear-operated maintenance valve that normally will be open and will require manual actuation by diver to close it.

A check and isolation valve spool will be installed approximately 2,000 feet downstream of the YMS riser. These valves are included in the design to isolate the section of pipeline adjacent to the FSRU from the rest of the Broadwater pipeline. The check valve will automatically contain gas downstream without manual intervention should there be a failure in the pipeline system inside the weathervaning radius of the FSRU. The isolation valve will require manual actuation by diver to close it.

The connection between the Broadwater pipeline and the 24-inch-diameter IGTS pipeline will consist of three spools and is depicted on Figure 2-12. The connection also is shown in schematic form on Figure 2-13a, and the associated excavation volumes are indicated on Figure 2-13b. The hot tap assembly and components will include a ball valve and a ring-type joint (RTJ) flange (with blind). This RTJ flange will be the connecting point for the spools that connect the Broadwater pipeline to the IGTS pipeline. The hot tap connecting spool contains the subsea shutdown and isolation systems at the pipeline end of line. This “T” shaped spool incorporates a check valve, which will automatically isolate the Broadwater pipeline from the IGTS pipeline without manual intervention by preventing a backflow condition from the IGTS pipeline, as well as a diver-operated block valve that is normally open. In addition, the pipeline tie-in spool incorporates a gear-operated maintenance valve that normally will be open and will require manual actuation by diver to close it.





FSRU SUBSEA TIE-IN SCHEMATIC

SCALE: N.T.S.

NOTES:

1. 30" CHECK VALVE TO BE PIGGABLE.

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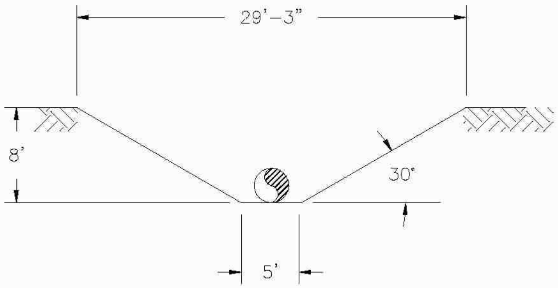

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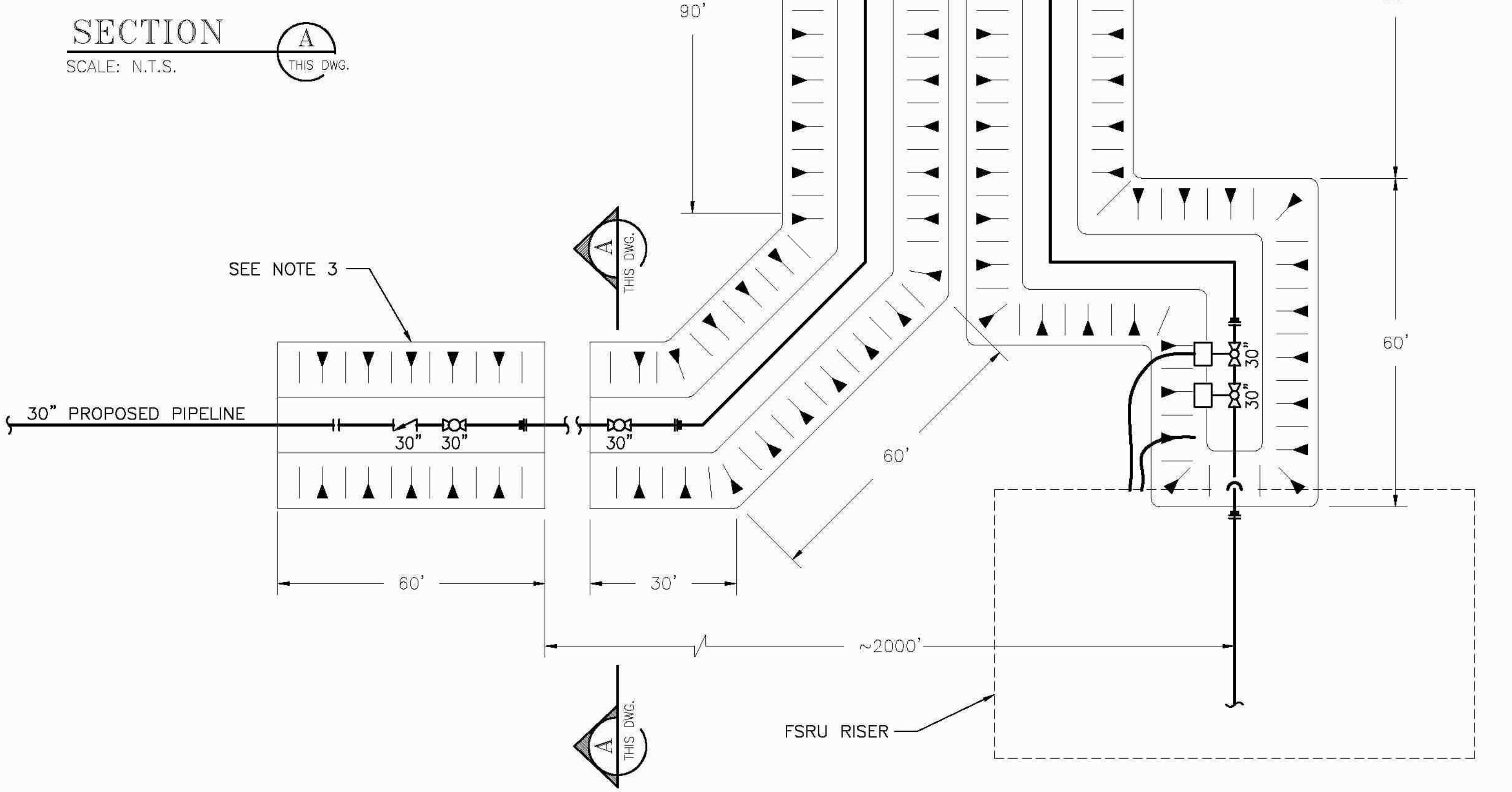

FSRU SUBSEA TIE–IN SOIL EXCAVATION VOLUMES

SCALE: N.T.S.

NOTES:

1. TRENCH CROSS SECTIONAL AREA IS APPROXIMATELY 123 SQUARE FEET.
2. TRENCH VOLUME IS APPROXIMATELY 44,550 CUBIC FEET ≈ 1,650 CU YARDS.
3. TRENCH VOLUME FOR CHECK AND ISOLATION VALVE SPOOL IS APPROXIMATELY 7,200 CUBIC FEET ≈ 270 CU YARDS.
4. SURFACE AREA OF TOP LAYER IS APPROXIMATELY 0.2426 ACRES FOR THE EXPANSION SPOOL AND 0.0403 ACRES FOR THE CHECK AND ISOLATION VALVE.

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FSRU SUBSEA TIE–IN
SOIL EXCAVATION VOLUMES

DRAWN BY:	S.E.M.	CHK'D. BY:	J.H.R.
DATE:	7-5-05	APPRV. BY:	T.O.
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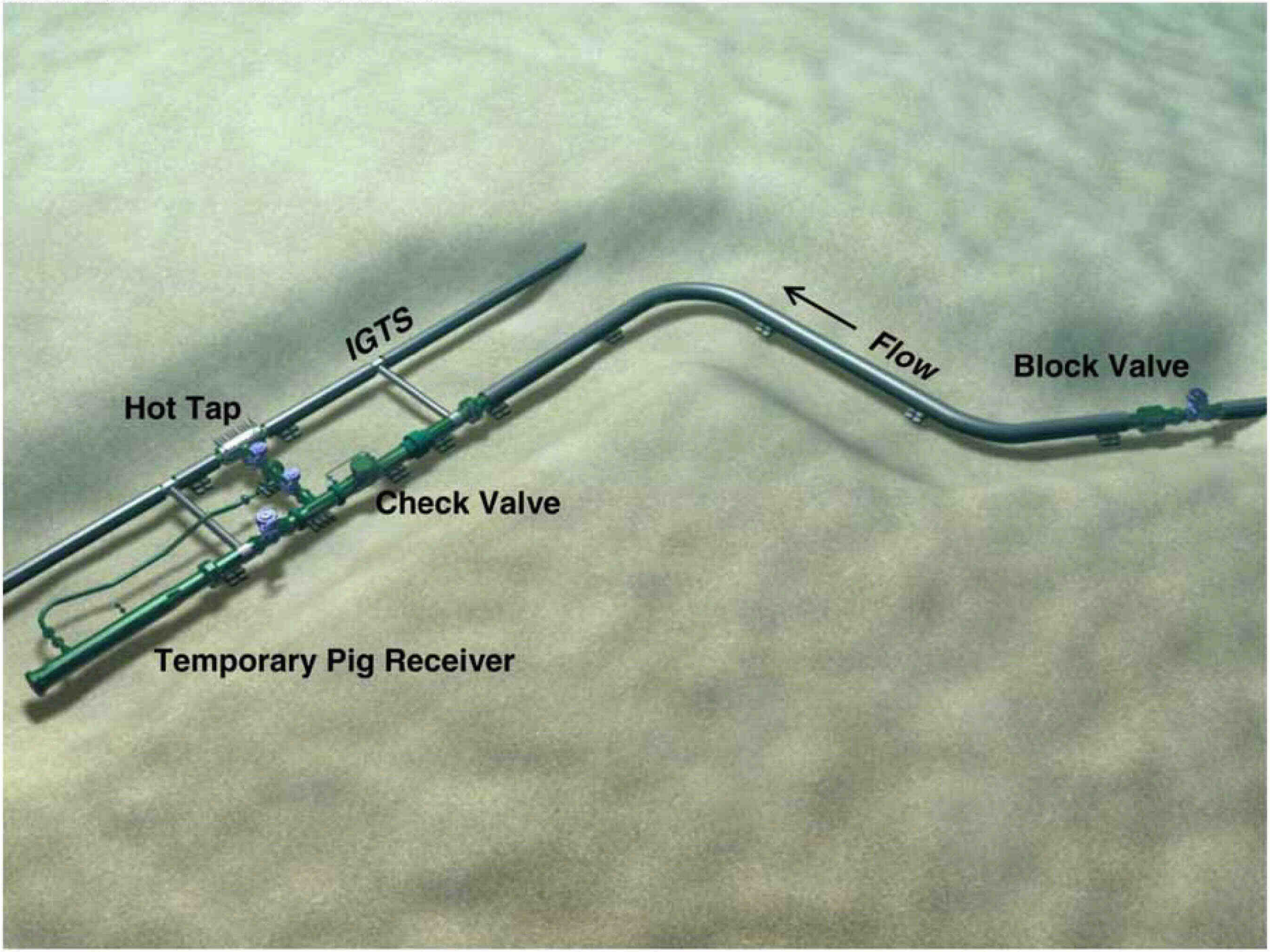
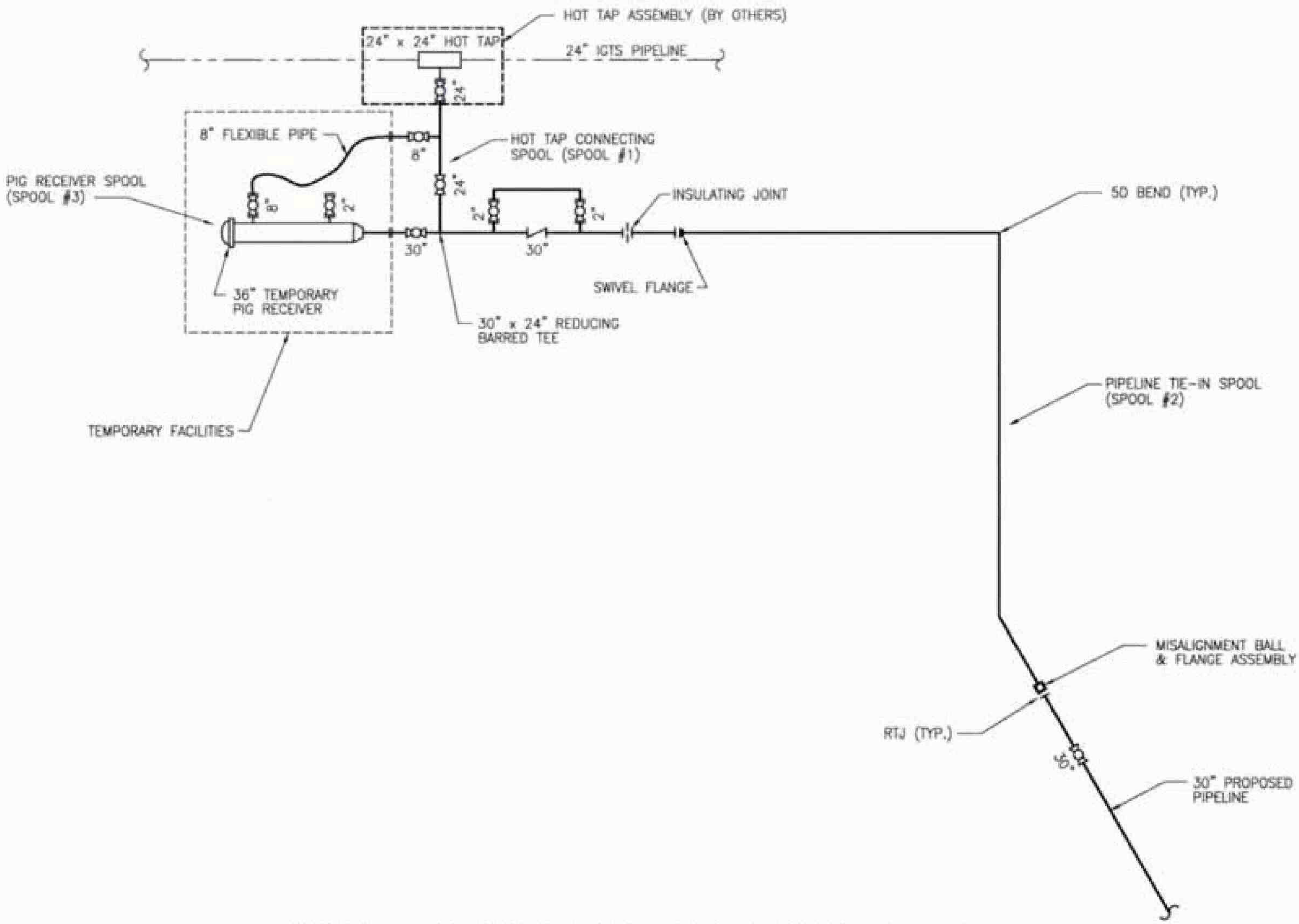


Figure 2-12 Depiction of Subsea Pipeline Tie-in with IGTS Pipeline



IGTS SUBSEA TIE-IN SCHEMATIC

SCALE: N.T.S.

NOTES:

1. 30" CHECK VALVE TO BE PIGGABLE.

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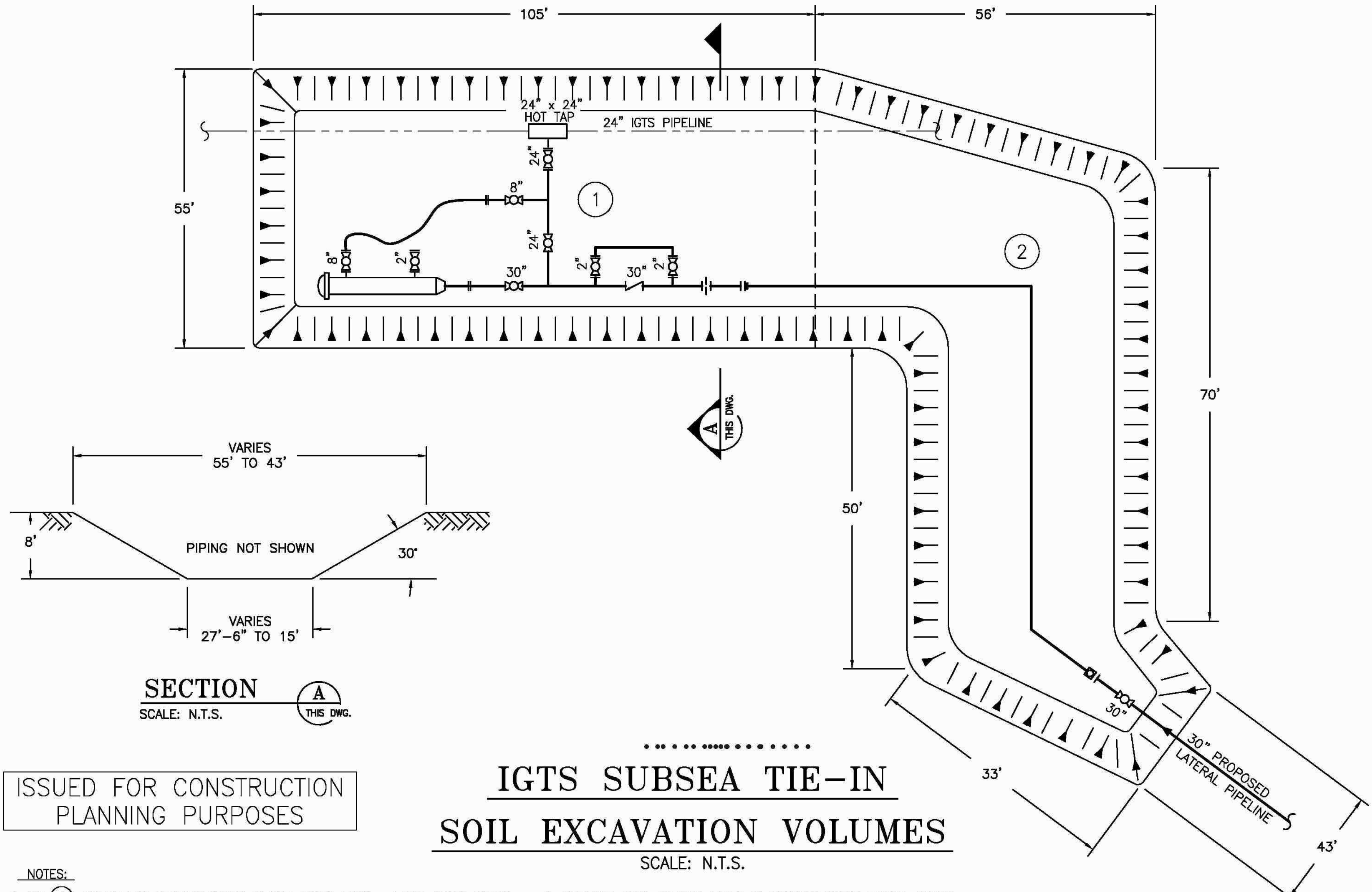

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IGTS SUBSEA TIE-IN
SOIL EXCAVATION VOLUMES

SCALE: N.T.S.

NOTES:

1. PIT (1) VOLUME IS APPROXIMATELY 31,887 CUBIC FEET ≈ 1,200 CUBIC YARDS.
2. PIT (2) VOLUME IS APPROXIMATELY 30,800 CUBIC FEET ≈ 1,140 CUBIC YARDS.
3. SURFACE AREA OF TOP LAYER IS APPROXIMATELY 0.2581 ACRES.

BROADWATER BROADWATER ENERGY	PROJECT CONSULTING SERVICES, INC. 3300 WEST ESPLANADE AVE., S., SUITE 500 METAIRIE, LA 70002-7406 (504) 833-5321 Fax (504) 833-4940 www.projectconsulting.com	IGTS HOT TAP, PIG RECEIVER & SUBSEA TIE-IN SOIL EXCAVATION VOLUMES	DRAWN BY: S.E.M. DATE: 7-6-05 DWG. NO. 05032-056	CHK'D. BY: J.H.R. APPRV. BY: T.O. REV D

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In the event it is necessary to evacuate the pipeline and the IGTS pipeline is not available for use, gas in the connecting pipeline will be directed to the flare stack on the FSRU.

2.1.3.2.7 Pigging Facilities

Pigging traps will be constructed for the various pigging operations required, ranging from post-construction cleaning and caliper pigging to the periodic operational maintenance running of intelligent pigs for pipeline integrity assessment. Traps are designed in accordance with applicable codes and regulations for fittings and connections to the pipeline. The launching trap will be placed on the mooring tower. The receiving trap will be a temporary trap installed near the subsea connection to the IGTS pipeline.

The IGTS Hot Tap Connecting Spool shown on Figures 2-12, 2-13a, and 2-13b will contain a flange connection for attaching the Pig Receiver Spool. The flange will normally have a blind attached that will only be removed when a pigging operation is scheduled. The receiver will be mobilized with a support diving crew when the pigging operations are performed. The receiver will be lowered to the tie-in spool, flanged into position and will receive the pig. Prior to removing the blind on the pig receiver flange, a pollution dome will be installed over the connection area to capture any hydrocarbon leaks that may occur during operation. During the pigging operation a NPS 24 valve that is part of the subsea connection assembly to the IGTS pipeline will be closed to direct gas flow through the receiver barrel. An 8-inch flexible pipe will be connected from the pig receiver to the NPS 24 valve assembly to allow the gas to continue through the pipeline as the pig is being received.

2.1.3.2.8 Pipeline Depth of Cover

The pipeline will be lowered below the seabed along its entire length such that the top-of-pipe is a minimum of three feet below the pre-disturbed natural bottom, wherever sediment conditions permit. Settling of the trench walls and natural sedimentation will be allowed to in-fill the excavated trench for the majority of the pipeline between MP 2.0 and MP 21.7.

If the minimum depth of cover cannot be achieved based on the sediment conditions and Broadwater determines that supplemental pipeline protection is needed, rock, concrete mats, or sand bags may be utilized to provide protection and pipeline stability based on site-specific conditions encountered at the time of construction. Rock and sand bag installation will be accomplished using drop tubes or similar means to ensure correct placement within the pipeline trench and over the pipeline. Concrete mat installation will be diver-assisted to ensure adequate coverage of the pipeline. The following locations will have additional protection and/or stabilization measures:

- The two cable crossings may need concrete mats placed over the installed pipeline where the pipeline bridges over the cable and if the top of the pipeline is less than three-feet below the natural sea-bed; and

- The tie-in locations at the FSRU and IGTS locations will have protective structures and/or protection materials in addition to some rock back-fill and sand/cement bags or grout bags.

Protective structures, if used, will be cage-like structures placed over the top of all or some of the subsea valve assemblies in the pipeline. The final requirements, design, and dimensions will be determined in the detailed design phase. The cage-like structures will be constructed of steel tubing and plate, and either steel or fiberglass grating materials. They will have the following approximate plan dimensions:

- IGTS tie-in assembly (including check valve, block valve, and associated bypass valves, blind flange, tie-over valves and hot tap assembly): 52 ft. x 32 ft.

- SSSV valve at tie-in with YMS riser: 31 ft. x 15X ft.

- Block valves at tie-ins with YMS riser and IGTS pipeline: 17 ft. x 15 ft.

- Block and check valve assembly at milepost (MP) 2.0: 30 ft. x 15 ft.

The protective structures, where used, will be installed by a dive support vessel (DSV) or other construction support vessel during installation of the various spools. At a height of about 10 feet they will protrude about 3 feet above natural seabed level except for the valves at the IGTS tie-in, where the IGTS pipeline was found to have about 8 feet of cover. Sand/cement or sand only bags can be used to transition the side slopes of the cage-like structures and, if necessary, concrete mattresses can be laid across the top portion of the cage to cover the access hatches for burial protection.

Design for Warm Gas Conditions

The send-out gas stream from the FSRU will be warm. Vaporized LNG will enter the subsea connecting pipeline at temperatures between approximately 90 °F and 120 °F to satisfy downstream IGTS requirements. To prevent excessive deflections of the subsea connecting pipeline due to thermal expansion, a pipeline expansion loop will be incorporated into the design immediately downstream of the SSSV (*see* Figures 2-10 and 2-11a). In addition, to constrain and stabilize the subsea connecting pipeline over approximately the first 2 miles from the FSRU (MP 0.0 to MP 2.0) it will be lowered below the seabed to a depth of cover of five feet then mechanically backfilled.

2.1.3.2.9 Compatibility and Integration with Iroquois Gas Transmission System

The Project is designed to increase the availability of natural gas to the New York and Connecticut markets through an interconnection with IGTS. The interconnection will be located subsea at MP 18.2 of the Iroquois Long Island Sound crossing.

IGTS Expansion Requirements

The Project is designed to take advantage of existing pipeline capacity in the southern region of the IGTS. No incremental pipeline looping or compression facilities on the current IGTS pipeline system are foreseen. Hydraulic analysis of the Iroquois system by Broadwater demonstrates that the existing pipeline can accommodate a wide range of pipeline system flows that, in turn, can accommodate the Broadwater gas input without additional looping or compression.

Downstream metering facilities may be required on the IGTS to affect deliveries to customers at new delivery points. None of those requirements have been identified to date. To the extent that these facilities may be required by IGTS' customers, impacts from the addition of metering or other minor facilities would not be expected to be significant and can be addressed when and if IGTS determines that those facilities are required.

Pipeline Design

The IGTS pipeline across Long Island Sound has the following material specification: 24" O.D. x 0.576" W.T. API 5L Gr. X60.

In its letter to the Federal Energy Regulatory Commission (FERC) dated October 7, 2005, IGTS stated that its pipeline from the Connecticut shore line to its Northport Sales Meter Station is designed to allow for a potential future increase above the current MAOP of 1,440 psig, subject to receipt of any regulatory approvals that may be necessary.

The Broadwater subsea connecting pipeline will be tested and qualified for an MAOP of 1,440 psig to match the current MAOP of the existing IGTS pipeline of 1,440 psig. The design of the Broadwater pipeline fittings and line pipe wall thickness will conform to the design philosophy utilized by IGTS. The increased design margin that results from adoption of the IGTS pipeline design standard provides an extra measure of public safety for the Broadwater subsea connecting pipeline in its Class 1 Location.

The initial design of the IGTS pipeline did not contemplate the direct connection of 1.0 bcfd of natural gas from LNG, or any other supply source, in the immediate Long Island and New York City region. By connecting the Broadwater FSRU and its LNG supply directly to the offshore portion of the IGTS pipeline, IGTS will benefit from an increase in throughput in the IGTS pipeline across the Sound, without a need for increase in the MAOP of the IGTS pipeline. A further benefit to IGTS is that, with the Broadwater Project attached, the need for new or expanded compression on the IGTS system onshore in Connecticut, or at any other point on its system, to be able to utilize an increase in the pipeline's MAOP, is potentially eliminated.

Gas Control

Day-to-day operations of the Broadwater FSRU and subsea connecting pipeline and of the IGTS pipeline will be integrated and coordinated. The FSRU command and control facility will exercise active control of gas send-out operations and emergency shutdown procedures on the FSRU and YMS, including operation of the SSSV on the subsea connecting pipeline at the base of the YMS mooring tower. The existing gas control center for the IGTS system in Shelton, Connecticut, will be in continuous, uninterrupted communication with the command and control facility on the FSRU and will monitor pipeline system conditions and deliveries into the subsea connecting pipeline system.

Gas Quality and Measurement

The Broadwater facility will manage send-out gas properties, including gas quality and heating value. Broadwater will meet the gas quality limits stipulated in the IGTS FERC Gas Tariff, as those tariff limits may be amended from time to time. The send-out natural gas stream will be sampled and measured on a continuous basis to ensure it meets IGTS' gas quality specifications at all times before it is transferred from the FSRU to the subsea connecting pipeline. An on-line gas chromatograph system on board the FSRU will provide continuous quantitative analysis of the vaporized natural gas. It will quantify the concentrations of the main natural gas components for the purpose of gas accounting, calculation of calorific value (heating value), and reference density for fiscal purposes and for check of gas quality conformity according to limits stipulated in the IGTS FERC Gas Tariff. Broadwater will provide IGTS with the ability to monitor the quality of the gas entering the Broadwater subsea connecting pipeline. Further, IGTS will itself be able to monitor the quality of the commingled gas stream in its system at onshore sampling and measurement locations through the addition of gas chromatographs.

Volumetric Measurement

Locating the Broadwater metering facilities on board the FSRU is significantly preferable in terms of environmental impact to building new metering facilities in Long Island Sound at the IGTS interconnect. Modeling and measurement tools capable of determining gas loss after measurement on the FSRU but before interconnection with the IGTS will be utilized as needed. Furthermore, the ability to measure gas volumes from the FSRU combined with aggregate volumes entering and exiting Long Island Sound on the IGTS will provide an adequate means to account for gas volumes.

Pipeline Emergency Shutdown and Isolation

Both the Broadwater and IGTS subsea pipelines include equipment features designed to increase the overall safety of the system and protect the public from a potential failure due to accidents or natural catastrophes.

The Broadwater pipeline will be equipped with a buried SSSV at the base of the pipeline riser and will be remotely controlled from the YMS and from the FSRU command and control facility in an emergency. A check and isolation valve assembly will be installed approximately 2000-feet downstream of the riser and will automatically isolate the section of pipeline adjacent to the FSRU from the rest of the Broadwater pipeline and contain gas downstream and prevent backflow should there be a failure in the pipeline system at any point upstream.

The connection between the Broadwater pipeline and the IGTS pipeline will incorporate a subsea shutdown and isolation system including a check valve. The check valve will isolate the Broadwater pipeline from the IGTS pipeline by preventing backflow from the IGTS pipeline. This will enable the IGTS pipeline to continue operating in the unlikely event of a shutdown of the Broadwater subsea connecting pipeline in an emergency.

Finally, as a fail safe, the integrated system of existing onshore remote control mainline block valves at each side of IGTS pipeline crossing of Long Island Sound together with the Broadwater SSSV will allow the combined Broadwater and IGTS subsea pipeline systems in the Sound to be quickly shut down in an emergency. This does not, however, imply that these systems must operate together in the event of a requirement to shut down flows from the Project. Broadwater intends to work with IGTS to develop an operating philosophy that will address potential interruptions in operations.

2.1.4 Location of Additional Information

A description of the FSRU facilities is provided in Section 1.3.2 of Resource Report No. 1 (General Project Description). More detailed design specifications for the FSRU are described in Resource Report No. 13 (Engineering and Design Material). A detailed description of the subsea connecting pipeline facilities is provided in Section 1.3.3 of Resource Report No. 1 (General Project Description). A detailed description of onshore facilities required is provided in Section 1 of the Onshore Facilities Resource Reports.

2.2 PROJECT CONSTRUCTION

2.2.1 FSRU Construction

The FSRU will be constructed at a qualified shipyard and will be towed to the site in Long Island Sound for final placement and installation. The hull will be built in pre-assembled units (blocks), which will have equipment and outfitting installed during construction. The blocks will be built in on-site workshops and will be assembled in a large dry dock at the shipyard.

During the transit from the shipyard to the proposed site, the FSRU will exchange ballast prior to the FSRU entering Long Island Sound. This will prevent the unintended introduction of foreign species into the aquatic habitat of the Sound. Ballast water management will be in accordance the International Convention for the Control and Management of Ships Ballast Water and Sea Water.

2.2.2 Construction of Tower Structure for YMS and Subsea Connecting Pipeline

2.2.2.1 Off-Site Fabrication

The tower structure is constructed in three main segments (jacket, topsides and mooring yoke), each of which is towed and sequentially installed on site before FSRU hook up, send-out pipeline connection and Project commissioning. The location of tower fabrication will be determined during the contracting stage. This location may be overseas at one or more of various established construction facilities.

2.2.2.2 On-Site Installation

The tower system includes a steel jacket structure that is fixed to the seabed by means of steel piles. The offshore installation work for the FSRU and pipe tower system will consist of installing the steel jacket on the seabed, driving the piles through the jacket pile guides into the seabed, fixing the piles to the jacket, attaching the topsides, connecting the mooring yoke to the jacket, hooking up the FSRU, mechanical completion of the riser and connecting the pipeline to the YMS.

The pile driving methods and arrangements for the jacket installation are subject to a geotechnical investigation and site survey. Sediment samples will be taken to a depth of 80 m and will form the basis of pile driving approach. It is not expected that any drilling will be required unless hard rock is found. As such, the pile driving will be carried out by hydraulic hammer. This will be completed from the water surface and entails a follower to be attached to the upper portion of the pile for driving. Depending on the sediment condition, the pile may be inserted in sections and welded to form a single pile length. The method requires a crane barge for jacket lifting, equipment storage and pile driving hydraulic hammer and power pack. The barge will be supported by three tugs for its positioning and fixing. Station keeping will be achieved by anchoring to the sea floor in a square anchor pattern of approximately 650 ft (200 m) side distance. This will be the approximate footprint required for tower installation. Two diving tenders will also be required on site throughout for guiding underwater operations. For installation of the jumpers, a dynamically positioned (DP) capable supply boat is anticipated.

After piling, the mooring system jacket will be installed and connected with the piles. After adjusting verticality, the annular spaces between the piles and guides will be injected with grout. The injection is carried out from the surface via flexible hoses and is controlled in situ by a diver or remotely operated vehicle (ROV). Procedures and materials will comply with API RP2 and be approved by the Classification Society. Very little or no grout will escape from the annular space, as injection is halted when the space is filled.

A proprietary grout widely used in the offshore industry, such as Ducorit S5 or equivalent, will be employed. This cement-based product, which consists of various minerals, is biodegradable and will have no environmental impact. The aggregates contained in the product will precipitate and other components, including plasticizers, will rapidly return to their original state (e.g., $CaCO_3$, Al_2O_3, SiO_2, and Fe_2O_3) without harm by reacting with water, forming hydroxides and CO_2.

When cured, the product can be considered a form of stone and will not be routinely replaced during the lifetime of the project.

To control stability during lowering of the mooring tower jacket, a shallow frame, or mud mat, is installed at the base of the jacket between the four legs. The mud mat is made of untreated lumber and has the sole purpose of providing stability control during jacket installation. The mud mat will be buried during the installation process by bottom sediments flowing around and through the framing. Sediment from the seabed will flow over the edges of the mud mat as the jacket settles onto the seabed, effectively burying it in the process. While the untreated lumber will remain buried in the sediment and may provide some habitat value, it is not intended as a biological habitat feature.

Other offshore installation work that will relate to the tie-in of the send-out pipeline to the FSRU via a subsea tie-in is described in Section 1.5.3 of Resource Report No. 1 (General Project Description).

Subject to the results of the geotechnical investigation, it is estimated that the full YMS installation will take approximately 29 days, assuming 12 hours operational time per day, with the sequence of activities as shown in Table 2-2.

Table 2-2 YMS On-Site Installation Sequence

Activity	Duration
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
Total	**29 days**

Various vessels will be mobilized into Long Island Sound by the tower system contractor:

- Crane Barge
- Support Barge(s)
- Tugs
- DSV
- Personnel Carrier and Utility Launch(es)

The workforce associated with the onsite tower system installation is estimated at 132 personnel of which, 64 personnel is estimated as the peak workforce over a duration of 14 days. The workforce will be involved in the following areas:

- Barge crew(s)
- Tug crews
- Divers and dive tender crew
- Crane riggers
- Welders
- Personnel carrier and utility launch(es) crew
- Manufacturer's supervisors and engineers
- Broadwater inspection personnel

For the vast majority of the workforce and time, housing will be on offshore vessels for the duration of the installation. However, hotel accommodation may be required on an ad hoc basis, particularly for transit. Medium- or long-term housing requirements other than the hotel accommodations mentioned above are not expected to be required.

2.2.3 Construction of the Subsea Connecting Pipeline

2.2.3.1 Overview of Pipeline Installation

The subsea connecting pipeline will be laid on the seabed and lowered using conventional underwater installation techniques.

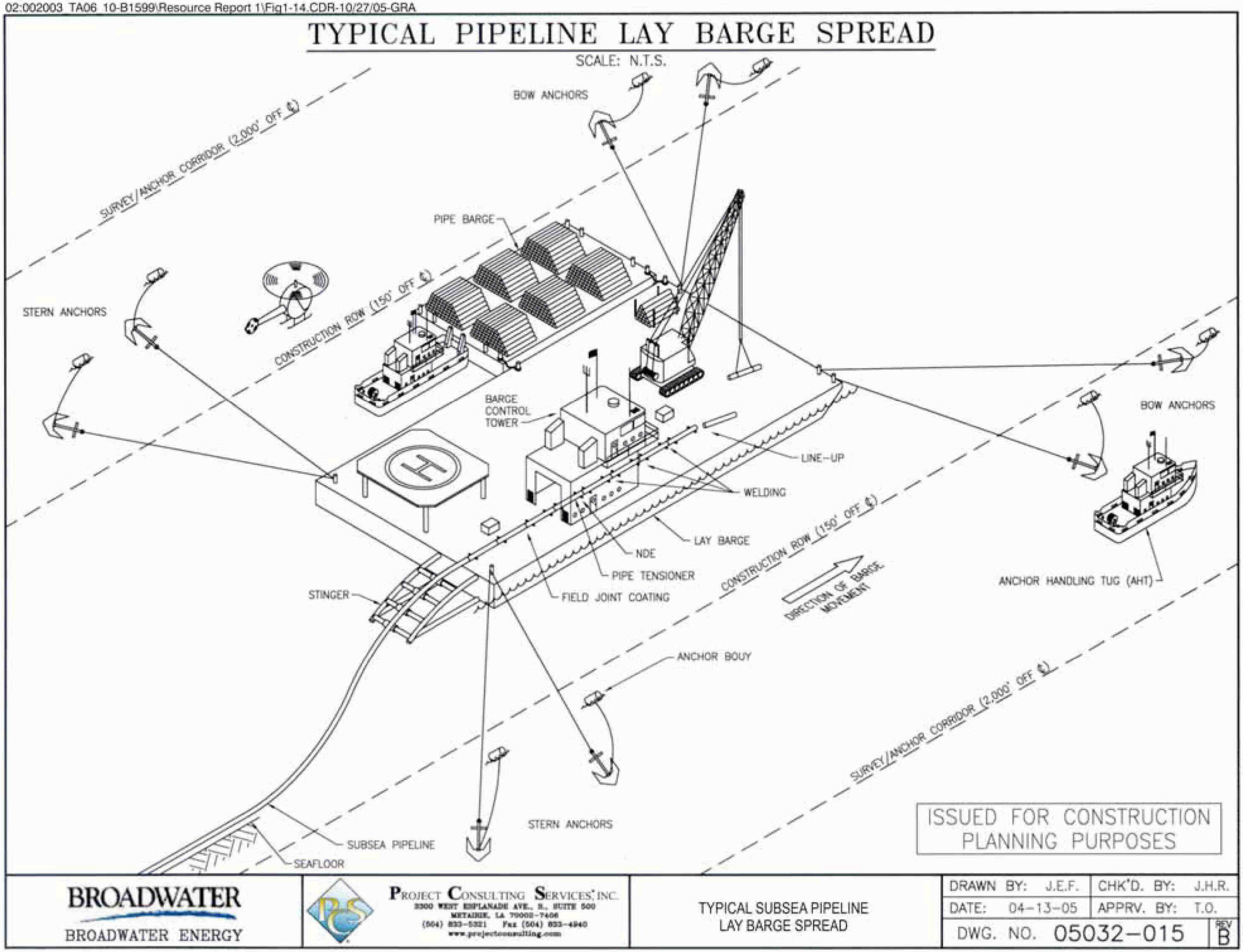
The majority of pipeline will be installed by a lay barge designed for this type of marine construction. It is the main piece of construction equipment that will be utilized. The lay barge has a variety of construction support vessels such as escort vessels, survey vessels, pipe supply barges and tugs, anchor handling tugs, and security, utility and personnel launches. The lay barge provides the work platform for the welding and inspection of the pipe joints (40-foot lengths of pipe) to make one continuous pipeline. The lay barge advances by pulling on mooring anchors and the pipeline is laid on the seabed off a "stinger" at aft end of the lay barge in a continuous operation as more joints of pipe are added. The lay barge will have accommodation for the marine and construction crews to work 24/7 in 8 or 12 hour shifts with associated catering and support facilities.

The secondary pipeline installation vessel will be a DSV. A DSV will be used to install the majority of the various pipeline spools at each end of the pipeline that are not installed by the lay barge, as well as to support any underwater work or inspection requirements. A DSV typically holds station with anchors, or it can be dynamically positioned (DPDSV). More information on DSVs and DPDSVs is provided in Section 1.5.3.9 of Resource Report No. 1 (General Project Description).

Upon completion of the pipe-laying operation, the pipeline will be lowered below the seabed along its entire length, wherever sediment conditions permit. In general, pipeline lowering can be accomplished by either pre- or post-trenching of the seabed. Pre-trenching is trenching prior to pipeline lay and is used if the pipeline needs to pass through very stiff material. Post-trenching means that the trenching equipment would remove sediment from the underneath and sides of the pipeline while the pipe lies on the seabed.

2.2.3.2 Pipe Lay

The pipeline will be installed utilizing a purpose built pipeline lay barge or vessel using an installation method known as S-Lay (*see* Figure 2-14). S-lay is a conventional method of installing pipelines in shallow to moderate depth waters. Segments of pipe, "joints," are stored on the lay barge and staged in a preparation area where the ends are beveled and cleaned. As the barge is maneuvered forward on anchors along the planned pipeline centerline in 40-foot steps, the prepared joints are positioned and added to the pipeline with successive welds performed at each of the dedicated welding stations positioned at 40-foot intervals along the barge in a controlled assembly line.


TYPICAL PIPELINE LAY BARGE SPREAD
SCALE: N.T.S.
BOW ANCHORS
SURVEY/ANCHOR CORRIDOR (2,000' OFF ℄)
PIPE BARGE
STERN ANCHORS
CONSTRUCTION ROW (150' OFF ℄)
BARGE CONTROL TOWER
LINE-UP
WELDING
BOW ANCHORS
LAY BARGE
NDE
PIPE TENSIONER
FIELD JOINT COATING
STINGER
CONSTRUCTION ROW (150' OFF ℄)
DIRECTION OF BARGE MOVEMENT
ANCHOR HANDLING TUG (AHT)
ANCHOR BOUY
SURVEY/ANCHOR CORRIDOR (2,000' OFF ℄)
STERN ANCHORS
SUBSEA PIPELINE
SEAFLOOR
ISSUED FOR CONSTRUCTION PLANNING PURPOSES
BROADWATER
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www.projectconsulting.com
TYPICAL SUBSEA PIPELINE
LAY BARGE SPREAD
DRAWN BY: J.E.F.
CHK'D. BY: J.H.R.
DATE: 04-13-05
APPRV. BY: T.O.
DWG. NO. 05032-015
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Figure 2-14

The pipe lay operation will be performed using a conventional anchored laybarge of approximate dimensions of 120 ft x 400 ft x 20 ft with an eight-point (or more) mooring system. The contractor will utilize a suitable and industry accepted means of installing the pipeline after demonstrating the adequacy of the proposed methods/equipment and accompanying pipe lay stress analysis.

Broadwater will ensure proper anchor placement and put in place measures to detect any unanticipated anchor movement. This will be achieved through careful anchor placement management. The planning of anchor placement in areas of concern will require the development and enforcement of an anchoring plan whereby each anchor placement is coordinated and placed at pre-determined locations. The location of each placed and recovered anchor will be recorded by the surveyors.

Anchor and cable management requirements will be developed during the detailed design stage and incorporated in the construction bid documents for the pipeline. The final anchoring and cable management plan will be developed after a marine pipeline contractor and specific equipment (laybarge and anchor-handling tugs [AHTs]) have been selected. The maximum distance from the centerline of the pipeline to anchor locations during construction will be approximately 2,000 feet (610 m).

AHTs will recover and relocate the barge/vessel anchors during the pipe lay and lowering operations. Where required, the AHTs will modify the anchor lines with mid-line buoys to avoid potential cultural materials or other identified bottom features requiring avoidance.

An average lay rate of 100 joints per 24 hour day working around the clock in shifts is anticipated, with a 25% weather and/or mechanical down time factor. Regional pipe hauling on barges will require a minimum of six assist tugs depending on the distance between the storage yard and the work site.

2.2.3.3 Pipeline Lowering

Primary Pipeline Lowering Method

Broadwater completed a geotechnical sampling and testing program to characterize the sediments along the pipeline route within the pipeline trench depth. Results are presented in Resource Report No. 7 (Soils). Generally it was observed that the sediments are mostly fine grained (silts, clays and sands) for over 95% of the route, with coarser material (gravel and cobbles) occurring at the Stratford Shoal Middle Ground. No hard bedrock was observed along the route.

Based on the observed sediment characteristics together with environmental impact concerns, plowing is Broadwater's primary choice for pipeline lowering. Plowing involves passive displacement of sediments by a plowshare as it is pulled forward. Plowing uses pull-barge or vessel force to overcome resistance of the plow being drawn through sediment and it is best suited to consistent silty clay sediments. The pull force is supplied by a special pull barge, or the lay barge itself. Steering is normally accomplished by offset or tow angle of the vessel or by articulated steering depending on the plow design. Monitoring of the depth of cut will be performed by the barge/vessel and occasional diver checks will be made to ensure that all instruments are recording correctly.

Broadwater proposes the post-lay plow method. Post-lay plows ride on the concrete coated pipeline, supported by rollers (*see* Figure 2-15). The plow will excavate a trench below the pipeline previously installed by the lay barge and the pipeline will be lowered into the furrow in the seabed as the plow is pulled ahead by the barge or vessel. Schematics showing typical plowed trench configurations are provided on Figures 2-16 and 2-17.

In Broadwater's pipeline construction plan and impact assessment it is assumed that a conventional anchored lay barge will be used to accomplish pipe lay and pipeline lowering. Information on the sediment impacts of pipeline installation can be found in Resource Report No. 7 (Soils) and Resource Report No. 2 (Water Use and Quality). Benthic effects are provided in Resource Report No. 3 (Fish, Vegetation, and Wildlife).

Multiple passes of the plow may be necessary to achieve the required depth of burial if hard-bottom areas are encountered. For most of the pipeline route it is expected that a single pass of the plow will lower the pipeline to the required depth. However, previous experience with the lowering of pipelines of similar or larger diameter suggests that Broadwater can expect an infrequent reduction in this lowering depth. Broadwater's pipeline construction plan conservatively contemplates two complete passes of the plow.

The expected geometry of the trench is based on an angle of repose of thirty-five degrees (35º). The multi-pass plow will clear the excavated material to a sufficient distance away from the trench to prepare the seabed for another pass. For an approximate 21.7 mile pipeline length the width of seabed disturbance at the top of the trench will be about 25 feet (not including spoil piles adjacent to the trench) and the total area of disturbance at the top of the trench will be about 67 acres (not including spoil piles adjacent to the trench).

Cable Crossings

The plow will be stopped approximately 160 feet prior to the crossing of the AT&T and Cross Sound cables. It will then be picked up and carried over the cables and plowing reestablished approximately 160 feet after the cable crossings.

The method of installing the pipeline across the cables is described in Section 1.5.3.6 of Resource Report No. 1 (General Project Description). Supplemental lowering of the pipeline at the cable crossings will be performed by divers and air-lift or similar equipment.

Spools and Tie-In Locations

The method of installing the pipeline at the IGTS and FSRU tie-in locations is described in Sections 1.5.3.4 and 1.5.3.5 of Resource Report No. 1 (General Project Description).

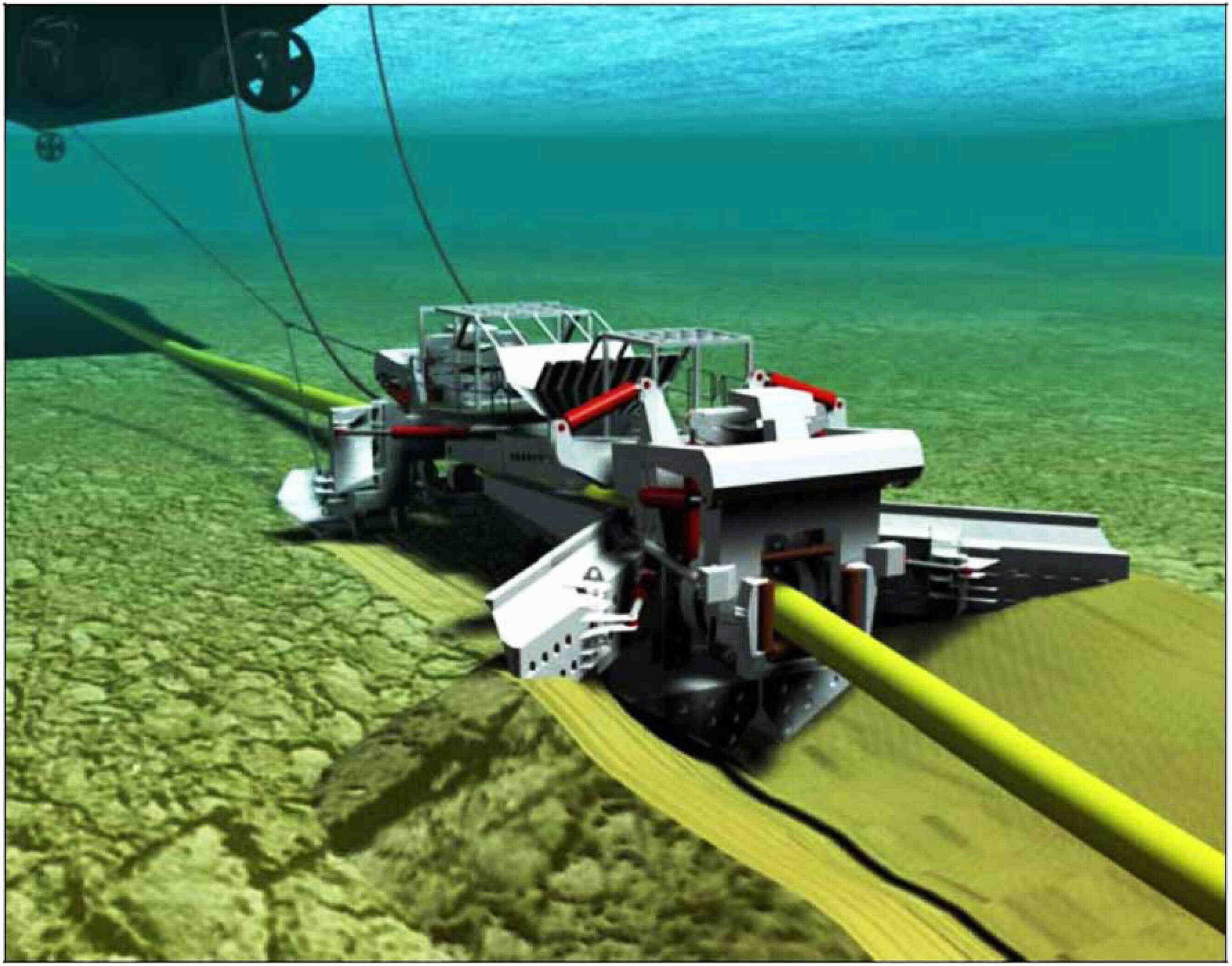
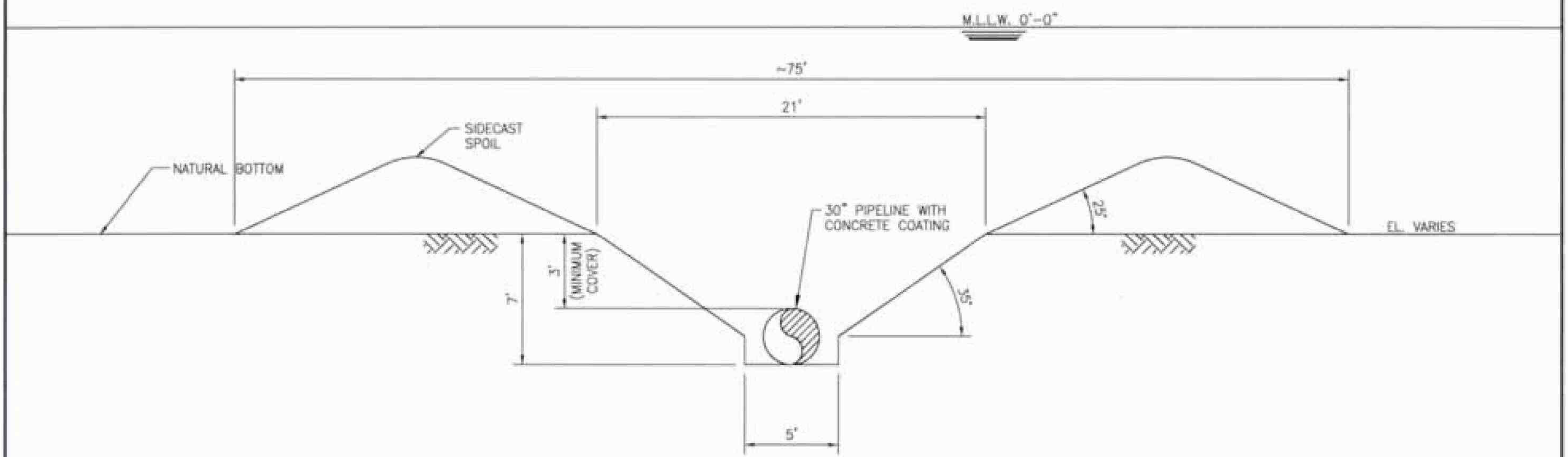


Figure 2-15 Depiction of Typical Subsea Pipeline Plow



TYPICAL SUBSEA PIPE DITCH BY TOWED PLOW METHOD (3 TO 4 FT. OF COVER)

SCALE: N.T.S.

NOTES:

1. TRENCH CROSS SECTIONAL AREA IS APPROXIMATELY 79 SQUARE FEET.
2. TRENCH VOLUME FOR 19.7 MILES IS APPROXIMATELY 304,500 CUBIC YARDS.

ISSUED FOR CONSTRUCTION PLANNING PURPOSES

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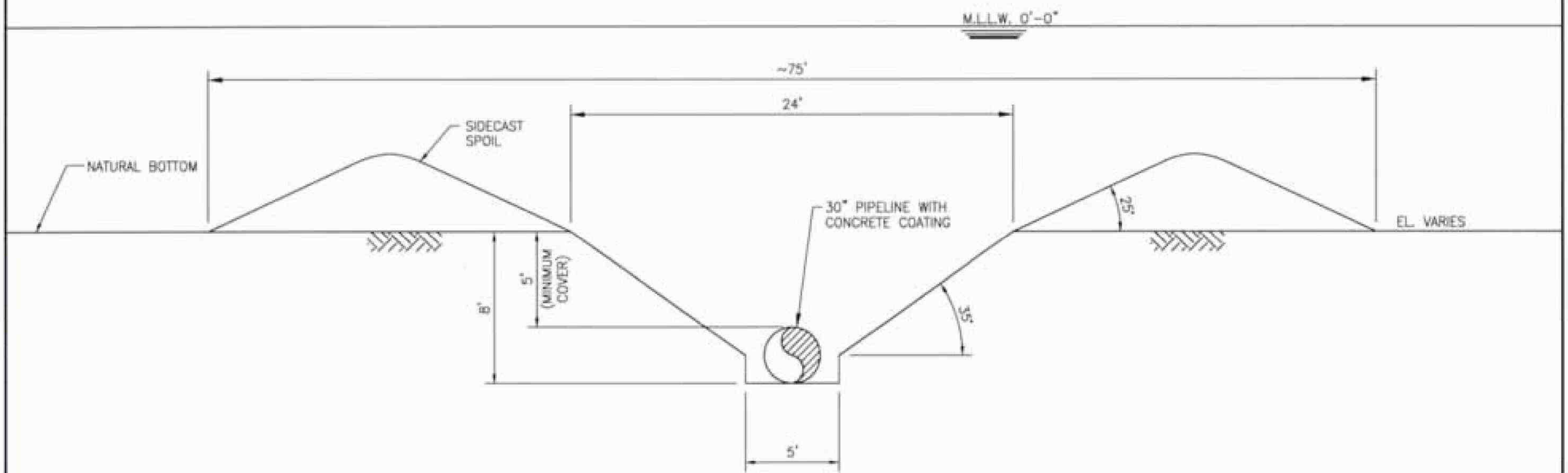
Figure 2-16



TYPICAL SUBSEA PIPE DITCH BY TOWED PLOW METHOD (5 FT. OF COVER)

SCALE: N.T.S.

NOTES:

1. TRENCH CROSS SECTIONAL AREA IS APPROXIMATELY 101 SQUARE FEET.
2. TRENCH VOLUME FOR 2 MILES IS APPROXIMATELY 39,500 CUBIC YARDS.

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Figure 2-17

Excavation of materials at the tie-in locations will be performed using submersible pumps and supplemented by divers. The excavation methods, locations and dimensions, spoil handling, backfilling, and measures to minimize potential impacts are discussed in Resource Report No. 2 (Water Use and Quality) and Resource Report No. 7 (Soils).

Special Topography

Broadwater's marine surveys completed during 2005 confirmed the presence of hard material in the Stratford Shoal area of Long Island Sound (MP 13 to 14, or just under 5% of the approximately 21.7-mile route); however, the instrumentation was unable to identify whether the material was mineral soil or solid rock. Subsequent direct observation showed the presence of pebbles, cobbles, and small boulders. The contingency plan for construction across Stratford Shoal is provided as Appendix C of Resource Report No. 1 (General Project Description).

Post-lay plowing in the Stratford Shoal crossing area will necessitate additional pull force and introduce the potential for the excavated boulders to damage the pipeline. A reduced rate of progress to permit closer monitoring of the trenching progress and immediate identification and removal of any boulders that may become lodged between the plowshares and the concrete weight coated pipeline will be utilized.

Contingency plans for a pre-pipelay trenching across Stratford Shoal will be developed and will include detailed discussions with suitable dredging contractors.

Sediment Resuspension

Lowering of the pipeline will result in the unavoidable resuspension of some sediments, which has the potential to affect water quality through increased turbidity and through reintroduction of buried contaminants to the water column. Based on sampling conducted by Broadwater in spring 2005, contaminant levels encountered during construction of the Project are not expected to be significant.

Broadwater completed a laboratory analysis of sediment samples collected along the extent of the Project and no elevated levels of contamination were identified. Broadwater also modeled the fate and transport of suspended sediments to determine the potential for water quality impacts and the potential impacts on marine organisms from sediment and contaminant deposition.

The modeling results demonstrate that increased sediment in the water column resulting from construction of the Project would have no significant impact to the water column, or to existing ecosystems within Long Island Sound. Detailed sediment transport results are provided in Resource Report No. 2 (Water Use and Quality).

To verify the modeling results that indicate that turbidity generated during the course of construction will result in only minor, temporary impacts, Broadwater will implement a monitoring program throughout the construction phase to characterize the actual sediment plume generated and to provide a comparison against modeled results. Monitoring will focus on defining the extent of the suspended sediment plume associated with the sediment disturbance. This will be accomplished using a combination of real-time instrumentation and laboratory analysis of water samples as follows:

- Periodic turbidity profiling measurements using in situ optical backscatter (OBS) monitoring equipment;
- Continuous in situ acoustical backscatter monitoring for suspended sediment using an acoustic Doppler current profiler (ADCP);
- Grab sample collection for laboratory analysis of total suspended solids (TSS);
- Periodic temperature and salinity profiling measurements using conductivity, temperature, and depth equipment; and
- Concurrent time and positional information using a differential global positioning system (DGPS).

The OBS and ADCP backscatter data will be used in conjunction with the grab samples for TSS to achieve wide spatial and temporal coverage of the anticipated suspended sediment plume in near real-time. Vertical profiling of temperature and salinity will provide information on ambient conditions that may be contributing to plume dynamics. All data will include time and positional information from the shipboard DGPS system.

2.2.3.4 Subsea Tie-in with YMS Mooring Tower

The YMS mooring tower structure will support the 30-inch pipeline riser that will tie in the newly laid subsea connecting pipeline with the FSRU. The riser will be pre-installed and hydrostatically tested during fabrication of the YMS.

Installation of the fabricated spools, including the expansion loop, will be performed after all lifts and construction activities are completed for installation of the YMS jacket, the YMS mooring head, and the YMS/FSRU mooring arm yoke. Spool installation will be performed using a DSV as the work platform.

The riser will have an RTJ flange with blind at its base. The RTJ flange will be positioned inside the profile of the structure for protection during transportation and structure installation. The riser will be flooded from the topside and the contractor will implement safety checks to ensure there is no differential pressure in the riser before diver connection operations commence.

2.2.3.5 Subsea Tie-in with IGTS

Hot Tap Connection

The existing IGTS subsea connecting pipeline will be modified to accommodate the subsea connection of the Broadwater subsea pipeline. This will be accomplished by installing a mechanical hot tap connection. The connector will be a split tee mechanical connection which, once installed, will allow for a branch connection through a 24-inch full-opening ball valve (*see* Figure 2-18).

The area including both the hot tap facility and the Hot Tap Connecting Spool will be excavated using submersible pumps and air-lift techniques.

Divers will mark the existing IGTS pipeline with buoys prior to the vessel setting up in the area. Anchoring patterns will be developed, reviewed and approved such that all anchors will be a minimum of 1,000 feet away on the far side and 500 feet away on the nearside from the pipeline. The area will be excavated to a suitable elevation below the natural seabed to allow ready access to the selected section of the IGTS pipeline for the Hot Tap installation and to an elevation that will accommodate the connecting spool and provide sufficient depth to minimize the profile of the spool components relative to the natural seabed (approximately 8 ft [2.44 m] below the sea floor).

After the area is excavated, the section of the IGTS pipeline to be tapped will be stripped of all concrete weight coating using water blasters. Saws and other such devices will not be used.

The hot tap will be lowered and attached to the IGTS pipeline. After all flanges and stud bolts have been tightened, flange spacing measurements will be verified to ensure the appropriate clamp compression has been obtained. The fitting will be leak tested and function tested to insure a proper seal around the pipe. The pipeline will be tapped utilizing a special hot tap tool and then the hot tap machine will be recovered. The pipe coupon, the section of pipe cut out, will be inspected to verify the integrity of the IGTS pipeline.

The design of the hot tap clamp has integrated a number of features to assist in the installation of the device, such as hydraulic opening and closing arms, piloted body studs, and tension-able packing flanges. The diver-assisted process does not require any welding, protecting the integrity of the operating line and overall pipeline system.

Fabricated Spools

The installation of the fabricated spools at the IGTS interconnection will be performed at different stages during construction:

- The Hot Tap Connecting Spool, because of its estimated size and weight, will be installed after completion of the pipe lay operation by the lay barge using its heavy-lift derrick;

- The Pipeline Tie-in spool installation will be performed using a DSV and will coincide with the final stages of the tower installation; and

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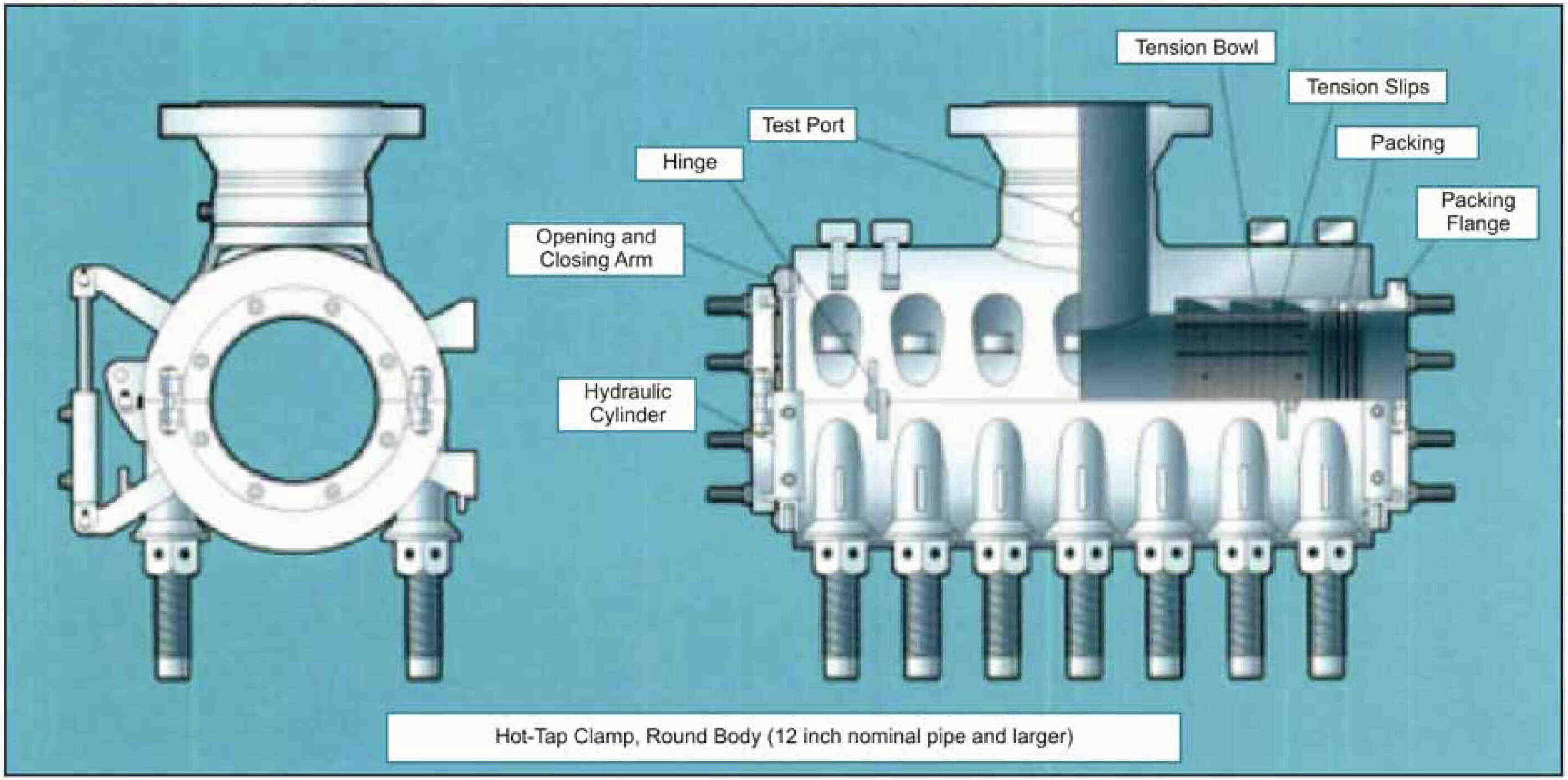


Figure 2-18 Depiction of Typical Subsea Hot Tap Clamp

- The Pig Receiver Spool will be installed by a DSV just prior to hydrotest operations. The pipeline valve upstream of the Hot Tap Connecting Spool will be closed and the Blind flange will be removed. The Receiver and associated piping and tubing will be installed then the pipeline valve will be re-opened. Upon completion of the pigging run, the valve will be closed, the by-pass line and Receiver, complete with the received pig, removed, the Blind reinstalled and the pipeline valve opened.

After the hot tap is securely attached and the lateral pipeline flanged to the assembly, the exposed pipeline and assembly will be covered to ensure proper coverage and protection. A blind flange will be secured to the hot tap protecting the tie-in flange for future spool installation. Divers will install sandbags and/or supports as required to support the added weight of the hot tap.

Later, a set of tie-in spools will be installed connecting the hot tap to the Broadwater pipeline. The attached spool section will be supported and sand bagged. Protective cover will be installed.

The Hot Tap Connecting Spool will contain a flange connection for attaching the Pig Receiver Spool. The flange will normally have a Blind attached that will only be removed when a pigging operation is scheduled. The DSV including dive team will mobilize the Pig Receiver Spool to site, close the pipeline valve upstream of the Blind, remove the Blind, connect the Receiver and the 8-inch flexible by-pass pipe to the 8-inch flange located on the 8-inch x 24-inch tee and reopen the pipeline valve. Upon completion of the pigging run, the valve will be closed, the by-pass line and Receiver, complete with the received pig, removed, the Blind reinstalled and the pipeline valve opened.

The protection of the valves and the hot tap will be required as a temporary measure during construction and/or as a permanent installation for the producing stage. Protection of the components can be provided using mats, sandbags, and/or prefabricated protective structures. However, as a general rule, all components that will require possible access during operation will be installed with a protective structure. This will also be the case, if any part of a component protrudes above the seabed.

2.2.3.6 Cable Crossings

The pipeline route, will cross two foreign utility cables during its installation. The two crossings are detailed below:

- AT&T – Owner: American Telephone and Telegraph Company; and
- Cross Sound Cable (CSC) – Owner: Babcock & Brown Infrastructure Ltd.

The AT&T cable is a fiber optic telecommunications cable which traverses from East Haven to Shoreham, Long Island. The cable is between 4 and 6 inches in diameter and is buried six to seven ft below the natural seabed.

The CSC cable is a direct current (DC) electrical power transmission cable consisting of a bundle of two solid dielectric cables and a fiber optic telecommunications cable, which traverses between New Haven and Brookhaven, Long Island. Each electric cable is 4.1 inches in diameter and the fiber optic cable is approximately 1 inch diameter. The CSC cable is buried 6 to 7 ft below the natural seabed.

Crossing Preparation

The Code of Federal Regulations 49 CFR Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards) requires a minimum of 12 inches of separation between cable and pipeline. However, an alternative separation may be determined during discussions with the respective cable owners. Broadwater will install a crossing bridge over each of the two foreign utility cables to establish the required separation.

As shown on Figure 2-19a and 2-19b, Broadwater will design a crossing bridge with appropriate pipeline transition based on pipeline and sediment characteristics and will develop construction drawings specifying the mat spacing and height required to achieve the agreed upon separation between the bottom of the pipeline and the top of the cable. Separation concrete mattresses will be placed over the existing cable to maintain the minimum agreed upon separation. Design calculations, proposed construction drawings and planned installation schematics will be developed by Broadwater and submitted to the cable owner for review, discussion and approval.

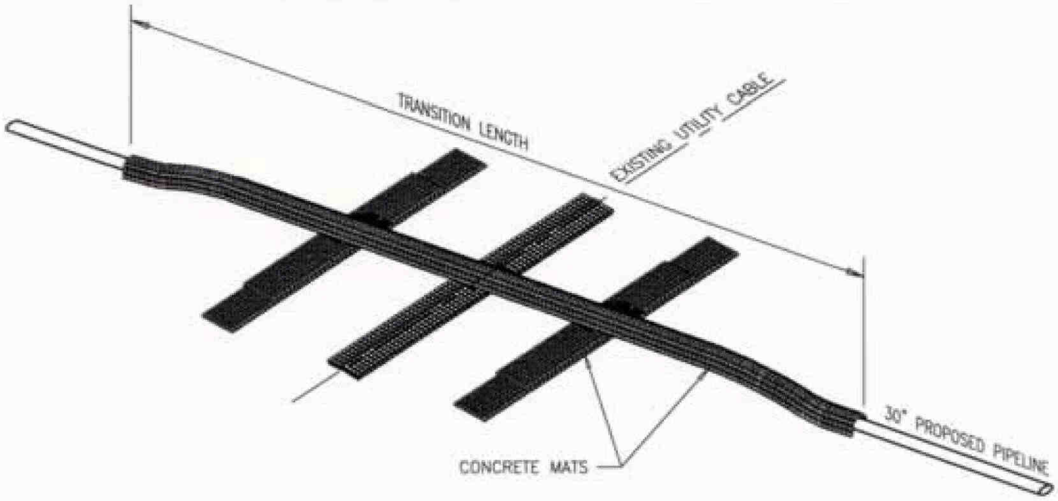
In order to verify safe and proper installation, the contractor will utilize high resolution sonar and diver-assisted investigatory equipment to locate the foreign cable. Prior to any site occupation by the pre-crossing spread and construction, the cable corridor will be physically marked and the as-found cable fixes entered into the barge or vessel's survey system. Broadwater will have cable crossing anchor patterns developed and will submit these to the cable owner for review and approval prior to commencing operations.

The contractor will excavate and then place pre-lay concrete mattresses on either side of the marked cable, creating a crossing bridge, in accordance with Broadwater and the Cable Owner's approved design. The contractor will then install the separation mattresses over the existing cable.

Crossing Completion and Protection

Following completion of the second pipeline lowering pass with the post lay plow, the contractor will complete the cable crossing in accordance with approved installation drawings. Pipelay operations, anchor vessel positioning and touch-down positioning will be monitored utilizing the most suitable surface and acoustic survey positioning and monitoring equipment to ensure that the pipeline is laid across the pre-installed bridge mattresses.

The pipeline will be lowered so that the top-of-pipe is three feet below the natural bottom, however the lowering operation will cease approximately 160 feet from the as-



TYPICAL FOREIGN UTILITY CROSSING

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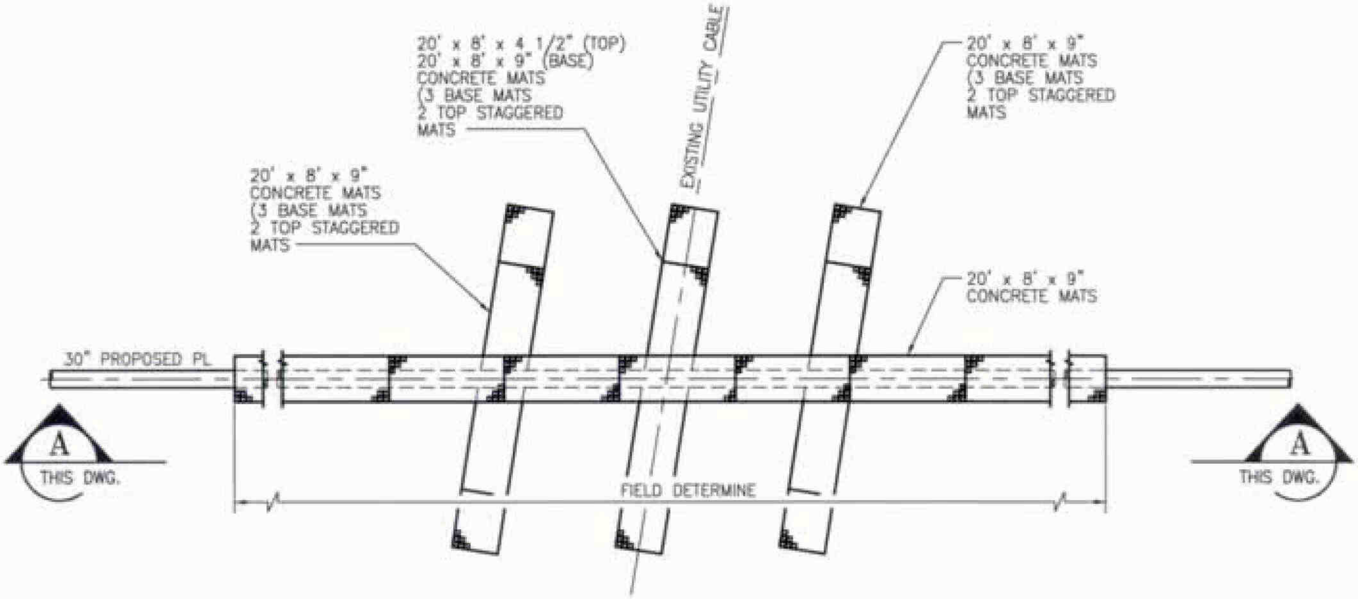

PLAN

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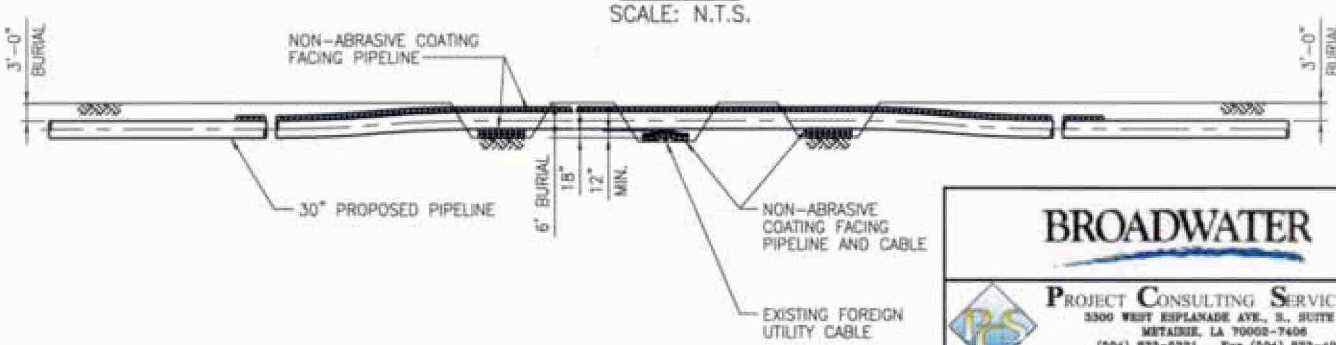

SECTION

SCALE: N.T.S.

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ISSUED FOR CONSTRUCTION
PLANNING PURPOSES

BROADWATER

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BROADWATER ENERGY
30" O.D. PIPELINE
TYPICAL FOREIGN UTILITY CROSSING

DRAWN BY: J.E.F.	CHK'D. BY: J.H.R.
DATE: 6-9-05	APPRV. BY: T.O.
DWG. NO. 05032-040	REV B

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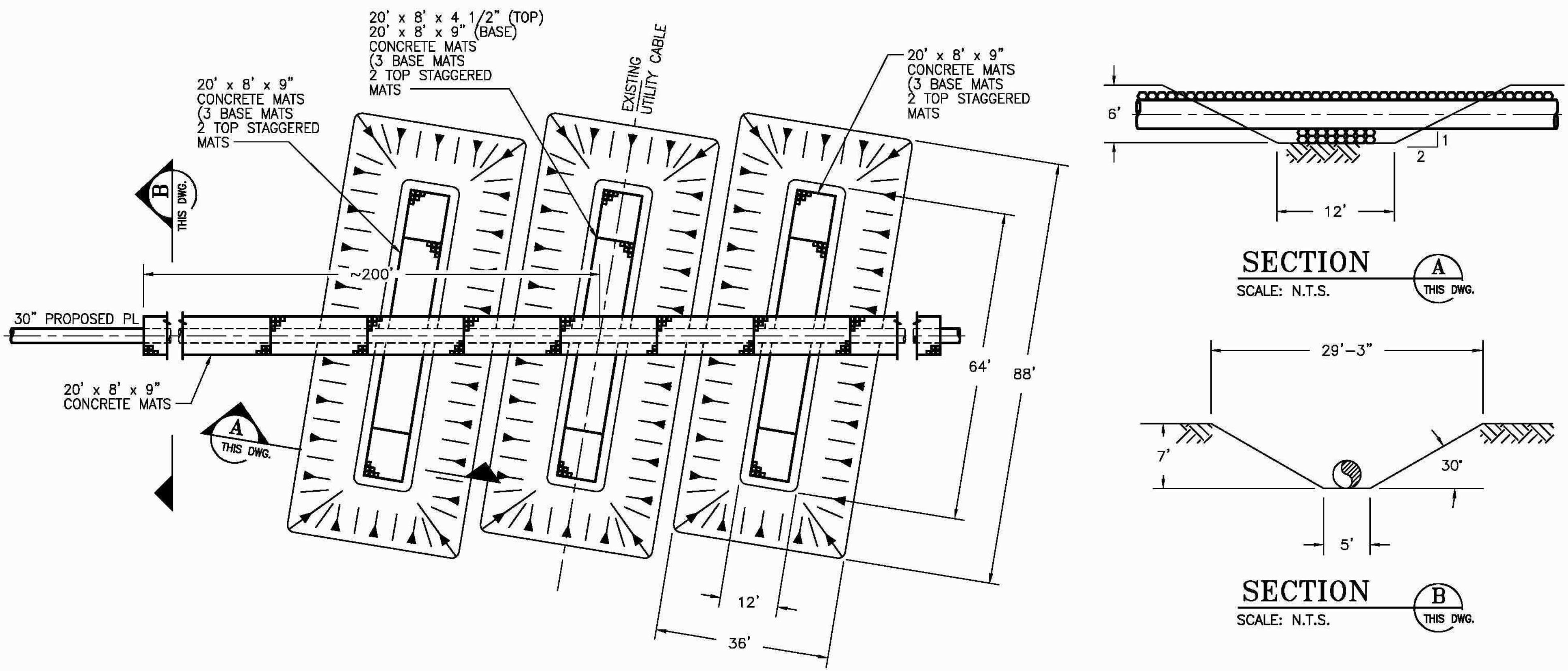

FOREIGN UTILITY CROSSING SOIL EXCAVATION VOLUMES

SCALE: N.T.S.

NOTES:

1. PIT VOLUME = 11,232 CU. FT. = 416.00 CU. YARDS
2. 2 CROSSINGS WITH 3 PITS PER CROSSING AT&T AND CROSS SOUND
   2 x 3 x 416 YD^3 ≈ 2,500 YD^3 FOR CABLE CROSSINGS
3. TRENCH CROSS SECTIONAL AREA IS APPROXIMATELY 120 SQUARE FEET.
4. TRENCH VOLUME FOR CROSSING TRANSITION IS APPROXIMATELY 2 x 200' x 120 FT^2 = 48,000 FT^3 = 1,778 YD^3/CROSSING.
   THERE ARE 2 CROSSINGS THAT PROVIDE A TOTAL TRENCH VOLUME OF APPROXIMATELY 3,556 YD^3
5. SURFACE AREA OF TOP LAYER IS APPROXIMATELY 0.829 ACRES (FOR BOTH CROSSINGS).

ISSUED FOR CONSTRUCTION
PLANNING PURPOSES

BROADWATER BROADWATER ENERGY	PROJECT CONSULTING SERVICES, INC. 3300 WEST ESPLANADE AVE., S., SUITE 500 METAIRIE, LA 70002-7406 (504) 833-5321 Fax (504) 833-4940 www.projectconsulting.com	TYPICAL FOREIGN UTILITY CROSSING SOIL EXCAVATION VOLUMES	DRAWN BY: S.E.M. CHK'D. BY: J.H.R. DATE: 7-6-05 APPRV. BY: T.O. DWG. NO. 05032-054 REV D

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found cable location. The pipeline will gradually breach the seafloor, ramp up the pre-installed concrete mattresses, cross over the foreign cable, and contact another set of concrete mattresses on the opposite side, creating a bridge with a minimum of 12-inches of separation between the bottom of the Broadwater pipeline and the top of the cable. The pipe will then gradually taper back downwards until the three-foot of cover is re-established. Airlifting of the material below the pipeline will be completed by divers and will result in the lowering of the pipeline onto the bridge supports. Portions of the pipeline with less than three feet of cover will be covered for protection with rock and/or concrete mattress such that there is a smooth transition back to natural bottom.

2.2.3.7 Backfilling

Backfilling of the trench will be accomplished by the settling of the trench walls and natural sedimentation except as noted below. The time between trenching and completion of natural backfilling of the trench is estimated to be 36 months, as discussed in Resource Report No. 2 (Water Use and Quality). While a residual depression may still be evident after 36 months, the bottom contours are anticipated to be within approximately 1 foot of preconstruction contours.

The first two miles of pipeline from the FSRU will be mechanically backfilled with clean fill. Material for mechanical backfilling will be imported from an approved location. This material will be comprised of rock that will be dumped from a suitable vessel to ensure accurate placement of backfill in the trench. Installation of the rock will likely be accomplished via drop tubes (or similar) to ensure accurate placement of the fill material and to minimize incidental deposition, and additional impact, of the fill material away from the trench line. As necessary, diver support will be utilized to ensure accurate placement of fill material. The length of time between trenching and mechanical backfilling will be approximately one month.

All areas requiring hand or submersible pump excavation (i.e., tie-ins, spools, cable crossings) will also be protected using mats, sandbags and/or pre-fabricated protective structures. To complete backfilling, and similar to the first two miles of the pipeline route, clean back-fill material will be imported and placed from a suitable vessel to ensure accurate placement of backfill in the trench.

2.2.3.8 Hydrostatic Testing and Dewatering

The installed pipeline, the riser on the YMS structure, and fabricated assemblies (spools) will be hydrostatically pressure-tested as required by regulation in accordance with 49 CFR Part 192.

Prior to the commencement of the filling operation, all work required for the installation of the pipeline will be completed, including lowering, span remediation and support installation at the two utility crossings. A barge or vessel will be mobilized that will support the pipeline filling, gauging and cleaning operation at either the FSRU or IGTS end of the installed pipeline.

Prior to initiating hydrostatic testing a cleaning pig propelled with seawater will be run to remove dirt and construction debris from the pipeline. The method used to remove construction debris ahead of cleaning pigs will be to recover solids after the pig has been received at the temporary receiver and the barrel containing the pig and debris will be recovered to the DSV.

Hydrostatic pressure testing will be conducted using filtered seawater. Suction hoses will be lowered into the water approximately 20 to 40 feet below surface to pump water into the pipeline. Filtering of the seawater will be performed during the flooding (pipeline filling) process to ensure that the water in the line is clean. The method used to filter seawater prior to transfer into the pipeline will be to pump the seawater through a U.S. standard sieve 200 mesh screen. The seawater will be treated using an injection pump and a storage/transfer system capable of handling the quantity of chemicals required for biocide injection.

A subsea temporary pig launcher head will be installed at the FSRU end of the pipeline that will be pre-loaded with all required gauging and filling pigs. The launcher will have a means of launching one pig at a time and have an inlet of sufficient size to allow a minimum flow rate of four thousand gallons per minute fill rate. A barge or vessel will be set-up at the IGTS end of the pipeline to attach a temporary pig receiver. The receiver will have a means to capture any debris not removed during the installation process and have a means to capture and dispose of water that will arrive before and after the pigs in a manner consistent with the regulatory requirements. Construction debris ahead of cleaning pigs will be captured for disposal.

To hydrostatically test the pipeline, the temporary launcher located at one end of the pipeline and the temporary receiver located at the other will be replaced with test heads. The high-pressure testing equipment will be connected to the test head to hydrostatically test the pipeline using the following equipment; a Dead Weight Tester, rotating chart, or a strip chart recorder that can be used to the same resolution, a calibrated test thermometer for recording ambient temperature, an accurate large diameter Bourdon tube type gauges (with mirror backing), graduated in pounds per square inch (psi). The range must indicate the specified test pressure near the middle gauge range.

The pipeline will be hydrostatically tested and monitored to confirm there will be no loss of pressure during the minimum 8 hours of test prescribed by code. After acceptance of the hydrostatic test, the pressure will be bled off and both pipeline end valves will be closed. Anticipated volume of water required to fill the approximately 21.7-mile-long pipeline is approximately 3,909,520 gallons. The intake and discharge locations could be located at either end of the pipeline depending on the Contractor's execution strategy.

After the installation of the YMS structure, the pipeline will be connected to the YMS with a three piece spool arrangement. At the IGTS end of the pipeline, the pipeline will be connected to the Hot Tap connector installed on the IGTS pipeline with a two piece spool arrangement. After these tie-ins have been completed, the dewatering (Pre-Commissioning) operation will commence using the permanent YMS pig launcher to launch the dewatering pigs. The dewatering pigs will be bi-directional, high sealing, and high performance polyurethane for maximum efficiency.

At the IGTS tie-in, a DSV with dive equipment and a team of divers will be set-up to operate the tie-in valves and to connect and disconnect the pig receiver. A storage barge may also be required to hold the fill medium during neutralization of the biocide treated water. When the dewatering pig is launched, the treated hydrostatic test water will be discharged from the pipeline and routed into a holding tank onboard the vessel or barge. In the holding tanks the biocide treated fill medium water will be neutralized using hydrogen peroxide with continuous analysis to ensure that a correct dosage is being injected. The injection operation will be computer controlled and monitored. The dosage rate can range from 150 ppm to 750 ppm depending on the remaining active constituent. The hydrostatic test water will be discharged back to Long Island Sound only after the biocide has been effectively neutralized. After the majority of the test water has been discharged and accounted for, the line will be dried and then purged with a slug of nitrogen. This will be followed by the introduction of dry natural gas.

2.2.3.9 Support Vessels

Support vessels will be mobilized by the pipeline contractor to assist the lay barge or vessel.

Typical Dive Support Vessel

Mooring for a typical DSV will consist of three or four anchors placed at pre-selected locations either by the DSV or with assistance from a support tug. The typical DSV has suitable back deck space to house the relevant diving and construction equipment and usually has minor fabrication facilities. The vessel will have accommodation for the marine and construction crews to work 24/7 in 8 or 12 hour shifts with associated catering and support facilities. DSVs are usually utilized for shallow to mid water work where short-duration diving operations and subsea construction is required.

Dynamically Positioned Dive Support Vessel

A DPDSV has redundant DP systems to ensure diver safety. No anchoring is required and the vessels are usually larger and more versatile than a moored DSV. The typical DPDSV will have saturation diving capability and will accommodate much larger marine, diving and construction crews. The vessel will be utilized in congested areas where anchoring is a concern, where the seabed is less than favorable for anchoring or where the work program necessitates that surface diving is uneconomical. A DPDSV will have accommodation and support facilities to house a large crew working 24/7 in 12 hour shifts. The DPDSV will effectively operate in water depths greater than 40 ft.

Anchor Handling Tugs

AHTs are different from normal tow tugs. They are designed and purpose built with more powerful engines, larger winches, and smaller back decks and lower centers of gravity for maneuverability. Pipe lay operations and pipeline lowering will proceed on a 24/7 basis. It is likely that the contracted lay barge will bring its own AHTs with experienced operators and crews to the Project for efficiency and safety reasons.

Survey Vessel

The survey vessel is anticipated to be in the 125-foot class or smaller. Survey vessels of this type are typically equipped with the following basic survey instruments: DGPS positioning, echo sounder, sidescan sonar, magnetometer, and pipeline and cable locator.

Pipe Supply Barge and Pipe Hauler Tug

Pipe supply barges are usually flat-top barges that range from 100 to 300 feet in length. They typically have no propulsion, but are hauled by conventional tugs that are available in the local area. Line pipe and other materials are loaded onto the barges at a suitable port location, hauled offshore to the lay barge, and offloaded by the lay barge's crane.

Hydrotest and Dewatering Support Vessels

Hydrotest support vessels are usually platform supply vessels with cranes and deck space capable of holding large amounts of equipment such as flooding pumps, air compressors to run the pigs, hose reels, pressurizing pumps, instrumentation and chemical injection pumps. Dewatering support vessels are usually platform supply vessels capable of holding large amounts of equipment such as compressors and dryers. Both the Hydrotest and Dewatering support vessels could hold their position using either anchors or DP.

Fall Pipe Vessel

A fall pipe vessel is usually a barge and/or vessel that is used for controlled placement of rock over the pipeline on the seabed.

Security and Escort Boats

The security and escort boats would likely be a vessel in the class of a harbor pilot boat or a lobster fishing boat. It accompanies the lay barge, if necessary, to keep other vessels fully aware of the lay barge's movements. Should any vessel (such as a pleasure yacht) inadvertently enter into the construction area the security and escort boats may sail out to the craft and ensure safe passage of the vessel out of the area.

Personnel Carriers and Utility Launches

These are common utility vessels of small class capable of transporting personnel and light materials to and from shore. These are typically chartered from local areas.

2.2.3.10 Timing and Duration of Pipeline Construction

FSRU hook up and commissioning is planned to commence December 01, 2010, with first gas by December 31, 2010. To accommodate this completion schedule the anticipated pipeline construction schedule and work sequence is as follows:

- September/October 2009: Pre-lay survey and/or diving operations will confirm seabed conditions – for example, to confirm that there are no new wrecks in the construction corridor. Note that a protocol for unanticipated discovery of cultural resources will be in effect for construction as described in Resource Report No. 4 (Cultural Resources – Privileged Information version).

- Main Pipe Lay - October 2009 through April 2010:
  - A DSV installs the IGTS subsea hot tap, cable protection and cable bridge supports;
  - The lay barge completes laying the pipeline onto the seabed and across the cable bridges, followed by pipeline lowering. The lay barge also installs the IGTS hot tap connecting spool, and the downstream FSRU tie-in spool which makes up one half of the expansion loop;
  - A DSV installs the check and isolation valve spool at MP 0.4;
  - The first 2 miles of the lowered pipeline are mechanically backfilled while a DSV completes cover and protection installation at the two cable crossings; then
  - Hydrotest vessels complete cleaning pig runs, then fill the pipeline with sea water and complete hydrostatic testing.

- Q4 2010: The FSRU/YMS contractor will set the pre-fabricated Mooring Tower jacket on the seabed at the FSRU site, and then install the four deep piles to secure the mooring tower (*see* Section 1.5.2.2 of Resource Report No. 1 [General Project Description]).

- Remaining Tie-ins - November/December 2010:
  - A DSV installs the remaining pre-tested tie-in spools at the IGTS and FSRU sites, followed by mechanical backfilling of the tie-in areas;
  - Hydrotest vessels de-water and dry the pipeline; then
  - Following receipt of the initial cargo of LNG, and supported by hydrotest vessels, the subsea connecting pipeline is purged of air with nitrogen and is then loaded with natural gas.

2.2.4 Temporary Onshore Land Requirements

To support construction activities, Broadwater will need to temporarily utilize onshore facilities to facilitate storage and transfer of materials to the construction site. The concrete weight coating will be applied to the pipe at an existing off-site concrete coating plant at a location to be determined during the detailed design stage. Companies capable of applying concrete weight coating for this Project from existing coating plant facilities include Bayou Companies, with locations in Louisiana, and Bredero Shaw, with locations throughout North America. The concrete weight coated line pipe will then be transported to a stockpile and transhipment site where it will be stored awaiting commencement of construction. A space of approximately 10 acres will be required to store the approximately 3,000 forty-foot nominal length joints of concrete weight coated line pipe for the Project.

Because the concrete weight coating will be applied at an existing facility, no environmental impacts associated with construction and/or use of temporary facilities are anticipated.

Following completion of concrete coating, the pipe will be transported via rail to an existing port lay-down area with adequate land-to-sea transfer capabilities, likely in the Port of New York/New Jersey. The actual location of the lay-down area will be determined by the contractor selected to install the pipeline. The use of an existing facility eliminates potential environmental impacts associated with establishing a new site for temporary storage of the pipe. From the temporary storage yard, the pipe will be loaded onto barges, transported to the Project area, and directly offloaded to the lay barge to minimize handling. No pipe storage yards will be needed on Long Island Sound. Upon selection of the temporary pipeyard, Broadwater will notify FERC and obtain appropriate clearances as needed.

During the course of construction, the contractor will need temporary space on the shore of Long Island Sound, primarily for shuttling crews and supplies to the Project site, since the majority of the construction operations will be conducted 24 hours a day, 7 days a week. The only waterfront facility required to support construction activities will be a dock. Based on the amount of existing dockage available in Port Jefferson and Greenport, Broadwater believes that existing facilities are adequate and that no new waterfront facilities will be needed. The contractor will most likely require the use of an onshore office and possibly warehouse facilities to support offshore activities during construction. The selected contractor will identify these locations prior to construction. Given the amount of marine usage throughout the Sound, Broadwater does not anticipate the need to construct new facilities to support temporary construction needs.

2.2.5 Cumulative Impacts

Cumulative impacts are those that result from adding the potential effects of a proposed project to the impacts of past, present, and reasonably foreseeable future projects in the area affected by the proposed project.

Through its extensive data gathering and field activities, Broadwater established the baseline conditions that exist in and around Long Island Sound, most particularly in the area proposed for siting the Project and against which the potential incremental impacts of the Broadwater Project could be assessed. That information was incorporated into the Resource Reports prescribed by the FERC's regulations implementing NEPA, specifically 18 CFR § 380.12. The conclusion of the Broadwater Resource Reports was that the impacts of construction activities associated with the mooring tower and pipeline connecting to the existing IGTS pipeline will be minor and temporary, particularly since the activities will be conducted over only a few months during the winter to avoid impacts on fisheries and minimize interference with commercial and recreational users of the waterway. The only other construction activity in the area would be the Islander East pipeline that may be constructed at some unknown future time. Even if both projects were to be constructed simultaneously, which is highly unlikely and speculative, the projects will impact different ecosystems within the Sound (with the Islander East Pipeline impacts affecting sensitive nearshore ecosystems that will not be impacted by the Broadwater Project). In addition, the projects are 1.5 to 2 miles apart at the nearest point and, as a result, the construction impacts (sediment resuspension and habitat disruption) would be minor, temporary, and are not expected to be cumulative.

With respect to operation of the FSRU, including temporarily docked LNG carriers, recognizing that the portion of the Sound where the facility is proposed to be sited is away from active commercial shipping lanes, the incremental impacts of the Broadwater Project are negligible. In addition, the nature of the air emissions and wastewater discharges from operations of the FSRU, which will be controlled, will have an insignificant incremental impact on regional air and water quality.

Finally, Broadwater's resource reports have identified the potential for temporary and intermittent disruption of maritime traffic patterns for vessels entering the Race as a cumulative impact from the introduction of two to three LNG carriers per week to supply LNG to the FSRU. The USCG is presently evaluating mitigation measures that may include, among others, intermittent diversion of shallow draft commercial and recreational craft out of the deep channel and sequencing of deep draft vessels through the Race, subject to the existing priority for Navy submarines departing from/traveling to the Groton Naval Base.

2.3 PROJECT OPERATION AND MAINTENANCE

2.3.1 FSRU Operation

Depending on the size of LNG carrier utilized, it is currently anticipated that two to three vessels will be unloaded each week. The FSRU is designed to accommodate LNG carriers in the size range of 125,000 m^3 up to a potential future vessel size of 250,000 m^3 capacity, but at this time the actual vessel sizes expected to call on the Broadwater facility have not been determined.

As part of the approval process for the Project to commence operations, a Letter of Recommendation from the USCG is required. Conditions arising from the Letter of Recommendation will be incorporated within a Vessel Management and Emergency Plan (Operating Plan). The USCG plan will contain specific requirements for the LNG carrier, pre-arrival notifications, scheduling, Long Island Sound transits, escorts, marine operations, cargo transfer operations, USCG inspection and monitoring activities and emergency operations. There may be other requirements for the transit and LNG discharge that may be different from other vessels operating in Long Island Sound. These conditions are still to be determined, but Broadwater anticipates at a minimum the following marine procedures.

- All LNG carriers destined for the terminal will be in possession of valid certification as required for International trade, including a USCG Certificate of Compliance for all non-USA flagged vessels.

- All LNG carriers destined for the terminal will be thoroughly reviewed by Shell following inspection under the Oil Companies International Marine Forum (OCIMF), Ship Inspection Report program.

- An LNG carrier on passage to the Broadwater Terminal will notify the Terminal, the USCG, the Immigration and Naturalization Service (INS), pilots, tug operators and shipping agents at least 96 hours before arrival. Advance notice will include validation that all onboard safety related systems and equipment are operational.

- The LNG carriers will remain at sea prior to an agreed arrival time at a location designated for a USCG Security boarding, if required, or at the pilot station. LNG carriers will not anchor in Block Island Sound to await pilots or other formalities.

- USCG inspectors may conduct a pre-arrival security inspection of the LNG carrier and crew before entering US territorial waters or before entering Long Island Sound.

- A state licensed pilot will board each LNG carrier for the transit through Block Island Sound and Long Island Sound. The same pilot will complete the docking and undocking operations at the FSRU and remain onboard throughout the discharge operation. The Broadwater terminal will confirm readiness to receive the LNG carrier prior to the pilot boarding.

- Coordinated scheduling of LNG carrier transits will take into consideration other marine users and avoidance of peak congestion at the Race.

- Broadwater will ensure that an adequate number of suitable tugboats are available for each LNG carrier operation. It is anticipated that each tug (up to four tugs in total) will be purpose-built to support Broadwater's operations and will have a bollard pull capacity of 60 metric tonnes. The tugs will likely be constructed at an existing shipbuilding facility within the U.S. with the capacity, ability, and proven track record for this type of construction without modification to its existing facilities.

  The tugs will be equipped with water fire-fighting equipment classed ABS Firefighting 1, and they will have an escort notation. Tug utilization (subject to USCG review and approval) is expected to be as follows:
  - Two tugs may be used to escort LNG carriers through the Race and during the transit of Long Island Sound;
  - Three or four tugs (depending on vessel size) will be required to assist the LNG carrier when berthing alongside the FSRU;
  - Two tugs will remain on standby in the vicinity of the FSRU whenever an LNG carrier is berthed. The duties of the standby tug will be to prevent other vessels from approaching the moored LNG carrier and to assist the vessel in the event of an emergency departure.
  - Two or three tugs (depending on vessel size) will be required to assist with unberthing operations.

Tugboat support considerations are also described in Resource Report No. 11, Safety and Reliability, Section 11.4.2.

- After berthing, an INS Officer will board the vessel to complete arrival formalities, including the verification of the crew against the previously supplied crew list.

- Following confirmation by the INS Officer to proceed, USCG personnel will complete safety inspections of both the FSRU and LNG carrier. A pre-discharge meeting will be held between the terminal and carrier staff to confirm discharge procedures and review of the safety checklist. Concurrent with these activities, a hard wired communications system will be established and tested between the carrier and the FSRU.

- On confirmation of the discharge procedures being agreed, the loading arms and Emergency Shutdown System (ESDS) will be connected. The ESDS allows either the terminal or LNG carrier to automatically or manually stop the unloading process whenever an abnormal condition occurs.

- After a successful test of the ESDS, LNG transfer may proceed according to the agreed procedures with the approval of the USCG.

- At the completion of cargo unloading operations, the loading arms must be drained and purged before disconnection, in accordance with standard LNG practice. The arms are drained by gravity either directly to the LNG carrier cargo tanks via the carrier's cargo lines or to the FSRU drain tank and thereafter pumped to the FSRU storage tanks.

The duration of activities associated with an LNG carrier unloading operation is shown in Resource Report No. 1, Table 1-5.

2.3.2 FSRU and Yoke Mooring System Maintenance

The FSRU and YMS are designed for high reliability and low maintenance. Maintenance plans will be developed at the detailed design stage. The maintenance regime will include frequent visual inspection (for the YMS this will be via permanently fitted access ladders); operational checks and tests; routine onboard mechanical and electrical maintenance; lubrication schedules and regular steelwork examination; and survey both above and below the waterline.

Both for the FSRU and YMS, underwater inspection may require some underwater surface cleaning of the hull and other parts. This will be performed generally to remove localized slime and weed growth originating from the Sound and will be completed using a light brushing system carried out by divers. It is expected that this will be undertaken no more than once per year. No recoating of the underwater portions of the facility will take place. Any mechanical repairs to the underwater parts of the FSRU or YMS will be segregated from the seawater by an underwater cofferdam applied by divers such that there will be no environmental impact.

For onboard maintenance other than the routine onboard mechanical and electrical maintenance set forth above, coating repairs will be ongoing. Proprietary epoxy and polyurethane paints will be used, and they will be applied mechanically, not sprayed. These and other solvents/cleaners will be similar to household-type products in their toxicity characteristics. Surface preparation will also include localized rinsing with freshwater to remove seawater spray salts carried by the wind from the Sound. All debris will be containerized and retained for disposal at a suitable facility.

2.3.3 FSRU Discharges

Operation of the FSRU will result in up to seven point-source discharges into the Sound, including:

- Two ballast water discharge points (port and starboard) located approximately 3 feet (1 m) below the waterline;
- One wastewater discharge point (either port or starboard) located approximately 3 feet (1 m) below the waterline;
- One desalinization overboard (starboard) located approximately 13 feet (4 m) below the waterline;
- One seawater cooling discharge (port) located approximately 13 feet (4 m) below the waterline;
- One inert gas scrubber cooling pump overboard (starboard) located approximately 3 to 6 feet (1 to 2 m) below the waterline; and
- One emergency bilge overboard (port) located approximately 3 to 6 feet (1 to 2 m) below the waterline.

If wastewater cannot be effectively treated to comply with New York State discharge requirements, then Broadwater will route black and gray water to holding tanks, which will be shipped to shore for disposal at an approved treatment facility. The emergency bilge overboard is not discussed in detail as Broadwater does not anticipate any discharge through this overboard for the lifespan of the Project.

FSRU operations also will include three non-point-source discharges into the Sound, including:

- One side-shell water curtain to discharge treated seawater between the FSRU and any moored LNG carrier as a hull integrity measure during offloading operations;

- Uncontaminated deck runoff from storm events; and

- Fire-water bypass system water.

All discharges are expected to meet New York State Department of Environmental Conservation (NYSDEC) discharge requirements for contaminant levels and other physical water quality parameters.

Most discharges from the FSRU will have a low residual (0.01 to 0.05 ppm) sodium hypochlorite concentration. Sodium hypochlorite is used to prevent marine growth in FSRU systems. Sodium hypochlorite concentrations will be monitored through sampling of overboard water collected from internal FSRU systems before it is discharged into the Sound. The chlorine concentrations of samples will be determined through a colorimetric assay. As necessary, the production and injection rate of the sodium hypochlorite added to the system at the sea chest will be adjusted accordingly.

Ballast Water System

No contaminants will be introduced into the FSRU's ballast water system prior to ballast water being discharged into the Sound.

Treated Wastewater from the Onboard Treatment Plant

The FSRU will be equipped with an MBR with the capability of treating both black water and gray water discharges. Based on the typical specifications for an MBR, it is anticipated that the discharge will be compliant with NYSDEC discharge standards. However, if, based upon review and consideration by NYSDEC during the SPDES evaluation process, it is determined that the discharges will not be compliant with applicable regulations, all black water and gray water generated by systems on the FSRU (e.g., sinks, shower drains, and floor drains) that may contain increased levels of detergents and nutrients will be routed to a holding tank and shipped to shore for disposal at an approved facility.

Discharge from the MBR will be tested weekly using an assay for the Most Probable Number (MPN) of viruses. The sample for this assay will be collected from the internal FSRU treatment system and sent off site for analysis. In addition, water quality monitoring plans will be prepared and implemented to ensure adherence to discharge standards in accordance with NYSDEC requirements as determined during the SPDES permitting process (*see* correspondence with NYSDEC presented in Appendix G in Resource Report No. 2 – Water Quality).

Desalination Unit Discharge

The desalination unit discharge will be used to discharge water generated by the desalination unit, which will be used to make potable water onboard the FSRU. The approximate volume of this discharge is 0.6 million gallons per day (2,355 m^3/d). The discharge will be comprised of seawater that had been taken in by sea chest and will have a slight salinity increase of approximately 2%. This equates to a salinity increase of less than 0.5 parts per thousand (ppt), which is not significant and not likely measurable since salinity values in the Sound range from 24 to 25 ppt. Based on these values, no impacts on water quality will occur.

Central Cooling Water (Non-routine Operations Only)

The central cooling water overboard will be used only if the FSRU's glycol/water system fails. The actual capacity of the cooling water system, and the associated discharges, will be determined during the final design stage of the Project. While this system will have a permitted discharge point, no discharge will occur under routine operating conditions. The seawater used for cooling will not come into direct contact with machinery onboard the FSRU. Therefore, no impacts on water quality will occur.

Inert Gas (IG) Scrubber Overboard

The IG scrubber is used only infrequently when a cargo tank needs to be purged for cleaning and/or inspection. The IG scrubber will be used approximately once every 5 years. Water from the sea chest will be used to "clean" and cool the inert gas stream used to purge the tanks. Water usage is estimated to be approximately 290,000 gallons/hr (1,100 m^3/hr), with a total of approximately 11.6 million gallons (44,000 m^3) required for a single purge of the entire FSRU.

Side-Shell Water Curtain

To maintain hull integrity of the FSRU and LNG carrier, a constant curtain of water will be directed overboard during LNG transfer from the carrier to the FSRU. Both the FSRU and the LNG carrier will generate side-shell water curtains.

This water will be supplied by the two sea chest intakes and thus will contain residual chlorine levels. The side-shell water curtain will discharge directly into the Sound between the FSRU and the LNG carrier. It is anticipated that water from the side-shell water curtain will be discharged at an approximate rate of 8,718 gallons/hr (33 m^3/hour) from both the FSRU and LNG carrier.

Drainage Systems and Deck Runoff

The fire-water bypass system will not be treated with sodium hypochlorite. Seawater for this system will be utilized only in the event of a fire onboard the FSRU (or testing of the fire-water system) and will be supplied by seawater intakes that are independent of the main seawater intake system. Discharge during any testing of the fire-water bypass system will be overboard via scupper drains, which will return the seawater directly back to the Sound. The volume of water to be used for testing is estimated to be 0.74 million gallons (2,800 m^3), and the testing will occur only once a month during system testing. Runoff from the testing of the fire-water system will not impact the temperature, salinity, or dissolved oxygen content of water in the Sound.

Uncontaminated storm water runoff from the FSRU will be comprised of rainwater and will be directed overboard via scupper drains. The volume of this runoff will be based on local levels of precipitation and will be at ambient temperature when drained to the Sound. Runoff from any on-deck location that has the potential for oil and grease contamination will be collected and routed to the bilge holding tank for shipment to shore.

Spill Potential

The potential exists for spills of various materials from the FSRU, which could enter Long Island Sound and impact water quality. Materials stored on the FSRU with spill potential include aqueous ammonia, ethylene glycol, diesel fuel, and mercaptan, which is used as a natural gas odorant. The diesel fuel will be stored in tanks intergrated into the hull of the FSRU, and the ethylene glycol is restricted to a closed-loop system, minimizing spill potential. The aqueous ammonia and mercaptan will be transported and stored in isotanks with adequate containment to minimize impacts.

These substances are discussed in more detail in Resource Report No. 11 (Safety and Reliability), Section 11.3.2.3. Per Spill Prevention, Control, and Countermeasures (SPCC) regulations (40 CFR Part 112) and the proposed revisions to the SPCC Rule (December 2005), facilities that become operational after August 18, 2006, must prepare and implement a plan before beginning operations. Broadwater recognizes this requirement and, preceding FSRU and pipeline operations in 2010, will prepare and submit an SPCC Plan in order to address the potential for spills of substances stored and utilized on the FSRU. The SPCC Plan will describe preventative and response measures that will be implemented in the event of a spill.

2.3.4 Subsea Connecting Pipeline

Operation of the subsea connecting pipeline will vary according to natural gas market requirements. Flow conditions on the FSRU and at onshore locations on the IGTS pipeline will be monitored using Supervisory Control and Data Acquisition (SCADA) systems by the Broadwater FSRU Command and Control facility and the IGTS Gas Control Center, respectively. Both facilities will be manned 24 hours per day. Operation and maintenance records will be maintained per the requirements of 49 CFR Part 192.

Regular pipeline maintenance will include maintenance and pigging at interval lengths specified by the U.S. Department of Transportation (USDOT), the applicant's standard operating procedures, NYSDEC regulations for pipelines, or as conditions warrant. Resource Report No. 11 (Reliability and Safety) provides a description of regular pipeline maintenance and emergency procedures for the pipeline.

Pigging Operations

Pigging during operations will be infrequent and will have the following general sequence of activities that will span approximately 10 to 14 days depending on weather and type of inspection required:

- With the support of a DSV and diving crew, in order to access the IGTS tie-in any protective devices will be removed and set aside on the bottom, and then backfill will be removed and set aside or recovered to a barge on the surface;

- A temporary pig receiver will be mobilized with the support of the DSV and diving crew and lowered down to the IGTS tie-in spool, flanged in position to receive a pig;

- The permanent pig launcher facilities are located on the deck of the YMS mooring tower. A launcher barrel will be pre-loaded with a pig onshore and flanged into position on the deck of the YMS mooring tower, or the pig will be transported offshore where it will be loaded into the pre-installed launcher barrel;

- The pig will be propelled with the send-out gas stream from the FSRU. Pig speeds will be controlled at the launcher barrel and by adjusting send-out gas flow rates;

- When the pig has been received at the IGTS interconnect, valves located at the receiver will be closed and the receiver barrel containing the pig will be recovered to the DSV. A pollution dome will also be utilized during recovery operations and will be brought to the surface for draining at an approved location (a description of the pollution dome is provided below);
  - Following completion of the pigging operation the blind at the receiver will be reinstalled, protective coverings will be re-established and backfill will be replaced similar to backfill procedures during the original construction, potentially supported by other vessels or barges; then
  - The DSV and any support craft will demobilize.

A pollution dome is an “umbrella” type mechanism that is placed above the area of an opening or disconnection during a subsea operation that may contain trapped hydrocarbons. The pollution dome can be tethered to the subsea equipment and/or suspended using floats or weights. The hydrocarbons will be captured in the pollution dome when the hydrocarbons bubble up in the water. The hydrocarbons are brought up to the surface via a hose connected to the top of the dome, and the hydrocarbons are then captured in a tank onboard the DSV.

In the case of the pig recovery operation, the pollution dome will be located just above a 2-inch vent valve once the pigging operation has been completed and the pig has been captured in the temporary pig receiver. Once the subsea tie-in assembly ball valve has been closed and the downstream valve of flexible hose connection is closed, the hydrocarbons trapped in the closed piping and flexible hose section will be vented to the topside through a hose or through the pollution dome assembly and contained on the DSV. The pollution dome assembly will then be relocated to a position above the temporary pig receiver connection to the subsea tie-in assembly to capture any hydrocarbons from the disconnection of the temporary pig receiver and the connections for the flexible hose.

2.3.5 Permanent Onshore Facilities

Although installation of the FSRU and connecting pipeline is not scheduled to begin until 2009, Broadwater has identified two locations on Long Island—Greenport and Port Jefferson—that can provide the facilities needed to support operation of the Project. Either one or both facilities would be used to support Broadwater operations. The location of each of the considered Long Island facilities is indicated on Figures 2-3 and 2-4. Greenport is located on the north fork of Long Island, and Port Jefferson is located southwest of the Project area on the north shore of Long Island. Permanent onshore facilities will include office space, warehousing, and a waterfront facility. Broadwater anticipates leasing existing facilities for these uses, and no land acquisition is proposed. These facilities will be located within existing marine facilities that are operated by others.

The office and warehousing facilities do not require waterfront access and thus will likely be established in existing facilities in general proximity to the waterfront facilities, but not necessarily co-located with the waterfront facilities. The office space will need to accommodate approximately six to ten people, with conference and training facilities available on site. The office will also function as the emergency response and communications center for the Project. Warehousing will be needed for spare parts, specialist tools, and equipment storage and handling. Broadwater expects that the location of these will be finalized following the selection of a specific waterfront facility. Onshore facilities are discussed in more detail in the Onshore Facilities Resource Reports submitted with the application.

3. ENVIRONMENTAL QUESTIONNAIRE

3.1 GENERAL

3.1.1 Need for and Purpose of the Proposed Work

3.1.1.1 Purpose

Based on historical trends and future projections, the Long Island, New York City, New York City metropolitan area, and Connecticut markets (the Region) are expected to face a critical period over the next 10 to 15 years in meeting the anticipated energy needs of consumers. The Project will provide a source of reliable, long-term, and competitively priced natural gas to the Region to meet this growing demand. To fulfill this purpose and need, a viable LNG import terminal site must meet, at a minimum, the following specific criteria:

- Be technically and economically feasible, practicable, and implementable;
- Maximize the buffer between the Project and populated areas;
- Have significant environmental benefits over other alternatives;
- Be able to provide reliable natural gas deliveries to the Region via pipeline connections while maximizing deliverability to New York City and Long Island;
- Provide deepwater berthing to accommodate LNG carriers up to a potential future size of 250,000 m^3 capacity;
- Provide for storage and vaporization facilities for at least 1.0 bcfd of natural gas, with an in-service date of 2010;
- Comprise a site that allows the terminal to maintain sufficient control and proprietary rights of operation;
- Comprise a site situated close to an existing pipeline system serving the Region with downstream takeaway capability greater than 1.0 bcfd; and
- Be able to ensure facility and interconnecting pipeline operability for a minimum 30-year project life.

3.1.1.2 Need

This section summarizes the need for the Project based on current and future trends of domestic natural gas supply, demand, and costs.

Natural Gas Demand

Total energy demand in the U.S. is projected to increase at an average annual rate of 1.4% from 2003 to 2025 according to the U.S. Department of Energy (USDOE), Energy Information Administration's (EIA's) *Annual Energy Outlook 2005* (*AEO 2005*) (EIA 2005a, page 3). This will result in an increase in total primary energy consumption within the U.S. from 98.2 quadrillion British thermal units (Btu) in 2003 to 133.2 quadrillion Btu by 2025 (*see* Figure 3-1).

With respect to natural gas, the EIA projects that demand within the U.S. will increase at an average annual rate of 1.5% through 2025. Nearly 75% of this increase is attributed to gas-fired power generating facilities and other industrial applications (EIA 2005a, page 4).

The projected increase in national demand for natural gas is outpaced by the projected requirements of New York. Natural gas demand within New York is expected to grow nearly 37% by 2021 from its current levels, with nearly 61% of this increase due to natural gas demand for electrical power generation (NYSERDA 2002, page 3-9). Of this amount, nearly 70% is projected for use in the area from Rockland and Orange Counties through Long Island (NYSERDA 2002, page 3-159).

As part of its assessment of the need for the Project, Broadwater commissioned an independent assessment of the northeast U.S. and eastern Canada natural gas markets. This study, completed by Energy and Environmental Analysis, Inc. (EEA), is provided as Appendix A of Resource Report No. 1 (General Project Description). In addition to the broader regional demand picture, the study also examined natural gas market growth in the New York City, Long Island, and southern Connecticut regions, which are adjacent to the proposed site of the Project. The conclusions of the study are as follows:

> Within the U.S. and Canada, the Northeast U.S. and Eastern Canada [NEEC] are among the most attractive for LNG imports. The area currently accounts for 14 percent of the total gas use in the U.S. and Canada with over 3.5 tcf annual consumption, and like the rest of North America, the area's gas consumption for power generation is likely to grow significantly in the foreseeable future. The area's total gas consumption is expected to grow by 1.5 percent annually, with total annual consumption reaching nearly 5 tcf by 2015.
>
> Current gas consumption in New York City, Long Island and Southern Connecticut, markets that would be directly connected to Broadwater, is approximately 700 bcf per year, or just under one-fifth of the total NEEC market. Recent market growth has averaged 2.7 percent per year. Similar to the region as a whole, most of the growth in gas consumption in this area has been driven by the power generation sector. In the past ten years, annual power sector gas consumption has increased by 100 bcf. Annual growth rate in the power sector have (*sic*) averaged 5.6 percent.

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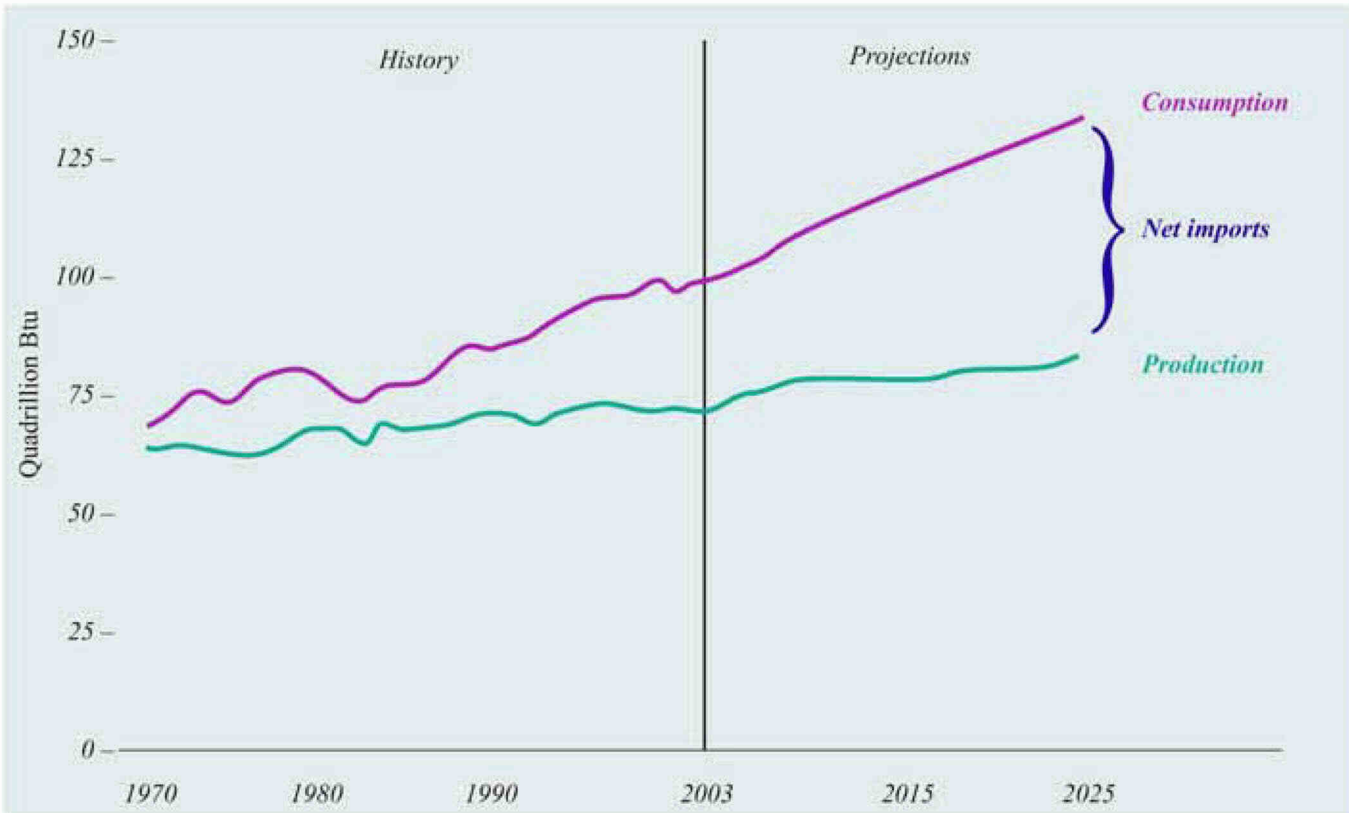


SOURCE: EIA 2005a

Figure 3-1 Total United States Energy Production and Consumption 1970-2025 (quadrillion Btu)

In an environment of increasing gas consumption, LNG imports will become an important source of gas supply for the area's consumers. Consumers would benefit in a number of ways from a new Broadwater facility. First, LNG supplies are a needed diversification to the supplies that originate in Western Canada and the Gulf Coast. Currently, Western Canada and [the] Gulf Coast supply 85 percent of the gas consumed in the area. LNG imports at Broadwater and other NEEC locations could potentially reduce that level to 60 percent. A Broadwater facility may reduce the need for future long-haul transportation that has proven difficult to build into the New York and New England markets.

(S*ee* EEA Report in Appendix A of Resource Report No. 1).

Natural Gas Supply

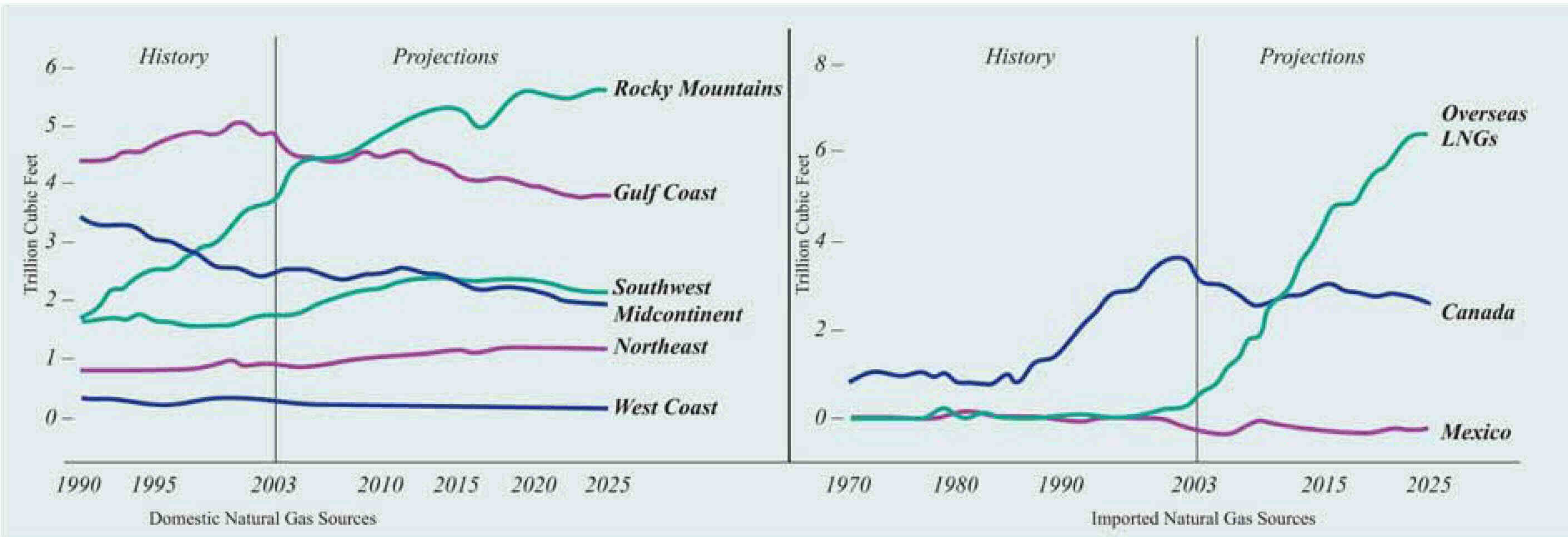
The natural gas supply for the U.S. currently comes from three sources: domestic production, imports from Canada, and a relatively small amount of LNG imports from overseas sources (*see* Figure 3-2).

Domestic production of natural gas has remained relatively flat over the past several years, and projected increases in production will not keep pace with projected demand. The *AEO 2005* (EIA 2005a) indicates total energy consumption is expected to increase more rapidly than domestic energy supply through 2025. Figure 3-1 presents a graph depicting total energy consumption and production for the years 1970 through 2025. To offset this imbalance, net imports of energy are expected to constitute 38% of the total U.S. energy use by 2025 (EIA 2005a, page 7).

Specifically, domestic onshore production of natural gas is projected to increase from 13.9 trillion cubic feet (tcf) in 2003 to 15.7 tcf in 2012, and then decline to 14.7 tcf by 2025 (EIA 2005a, page 7). This limited increase in supply is attributed to slow growth in gas reserves, fewer new discoveries, and higher exploration and development costs (EIA 2005a, page 7). Domestic offshore production of natural gas is projected to increase from its current level of 4.7 tcf to nearly 5.3 tcf by 2014, and then decline to 4.9 tcf by 2025 (EIA 2005a, page 7). Anticipated trends are presented on Figure 3-2.

Imported Canadian supplies of natural gas are projected to decline from their current level of nearly 3.1 tcf to approximately 2.5 tcf by 2009 (EIA 2005a, page 7). However, from 2010 to 2015 supplies of Canadian natural gas are projected to increase to nearly 3.0 tcf due to higher anticipated natural gas prices, the introduction of additional natural gas from the Mackenzie Delta region, and increased coal bed methane production (EIA 2005a, page 7). By 2025, the U.S. importation of Canadian supplies is again projected to decrease to approximately 2.6 tcf in response to reserve depletion and a growing Canadian domestic market (EIA 2005a, page 7) (s*ee* Figure 3-2).

The natural gas supply for the Northeast U.S. is dependent upon major interstate and intrastate pipeline systems for access to domestic and imported Canadian gas supplies (NYSERDA 2002). Domestic natural gas accounts for approximately 62% of the natural gas supplied to the New York region, with nearly all of the remainder coming from



SOURCE: EIA 2005a

Figure 3-2 Domestic and Imported Natural Gas Sources

Canadian sources (NYSERDA 2002, page 3-153). Although natural gas production within New York State is increasing, this supply accounts for only 2% of the natural gas consumed annually in the state (NYSERDA 2002, page 3-153).

In summary, the projected growth in U.S. natural gas supplies will depend on unconventional domestic production, natural gas from Alaska, and imports of LNG (EIA 2005a, page 8), with the net import of natural gas making up the difference between projected U.S. production and consumption. All forecasts show domestic production providing a decreasing share of total natural gas supply.

Natural Gas Prices

On a regional basis, natural gas commodity prices in the New York and Connecticut region have shown a clear tendency towards both an increase in the average price level and increasing price volatility or variation around the average price level.

As Table 3-1 shows, New York City gate prices averaged $2.93 per thousand cubic feet (mcf) over the five-year period from 1995 to 1999. Over the next three years (2000-2002), New York City gate prices averaged $4.37 per mcf, an increase of 49%. Over the years 2003 and 2004, average price levels increased an additional 35%. A similar situation has unfolded in Connecticut.

Table 3-1 Historical New York City and Connecticut Gas Prices

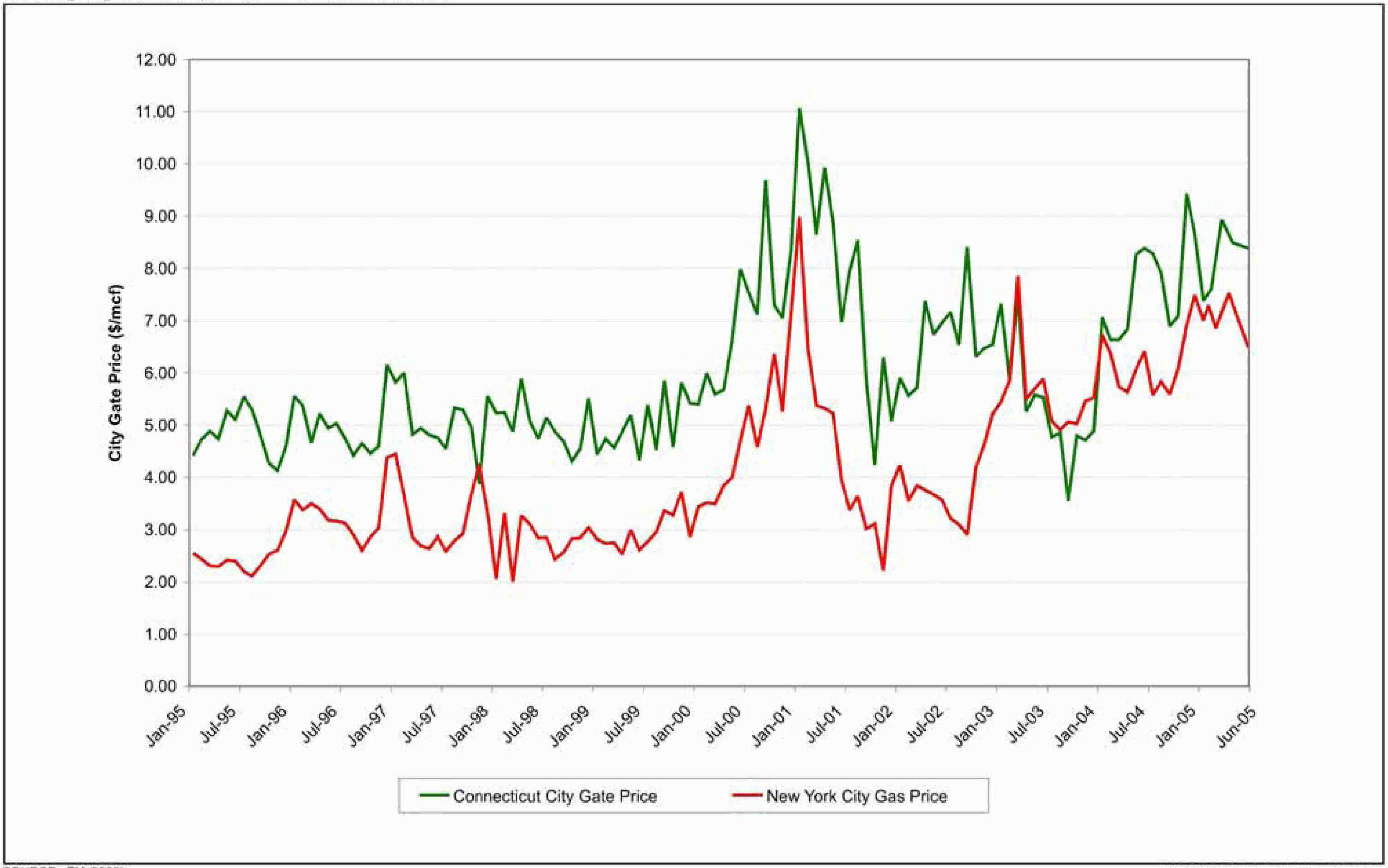
	1995 – 1999 Period	2000 – 2002 Period	Jan 2003 to Jun 2005 Period
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

[illegible]

In addition to the increasing price level of natural gas in the region, volatility of natural gas prices has also increased. Figure 3-3 presents the monthly city gate prices for New York City and Connecticut from January 1995 to June 2005 (EIA 2005b). The increasing variation in natural gas prices, particularly in the winter months, is apparent. There are a number of reasons for this increasing volatility. First, the growth in natural gas transportation serving the Region has not kept pace with growing demand. Furthermore, gas markets in the New York City and New England areas are closely connected because of New England's reliance on pipeline flows on the Algonquin Gas Transmission and Tennessee Gas Pipeline systems coming through the New York City and Connecticut area. The pipeline linkage between the two areas causes gas prices in the two regions to be tightly linked and to react to events in either market.

Second, a significant proportion of the new electric power generation in the Northeast U.S. is gas-fired. For example, in New York, fully 50% of the generating capacity for



SOURCE: EIA 2005b

Figure 3-3 Monthly City Gate Natural Gas Prices for New York and Connecticut (Jan. 1995 to Jun. 2005)

2005 is either gas-fired or dual-fueled (capable of burning oil or natural gas) (NYISO 2005, page 17). During periods of extreme winter weather, this produces coincident demand spikes for both natural gas and power.

The need to address these issues of increasing price levels and volatility has been noted recently in the New York Independent System Operator's (NYISO's) recent publication *Power Trends 2005*: "The nation in general, and the Northeast in particular, must fashion an effective fuel diversity strategy for dealing with the increasing use and dwindling domestic reserves of natural gas" (NYISO 2005, page 19).

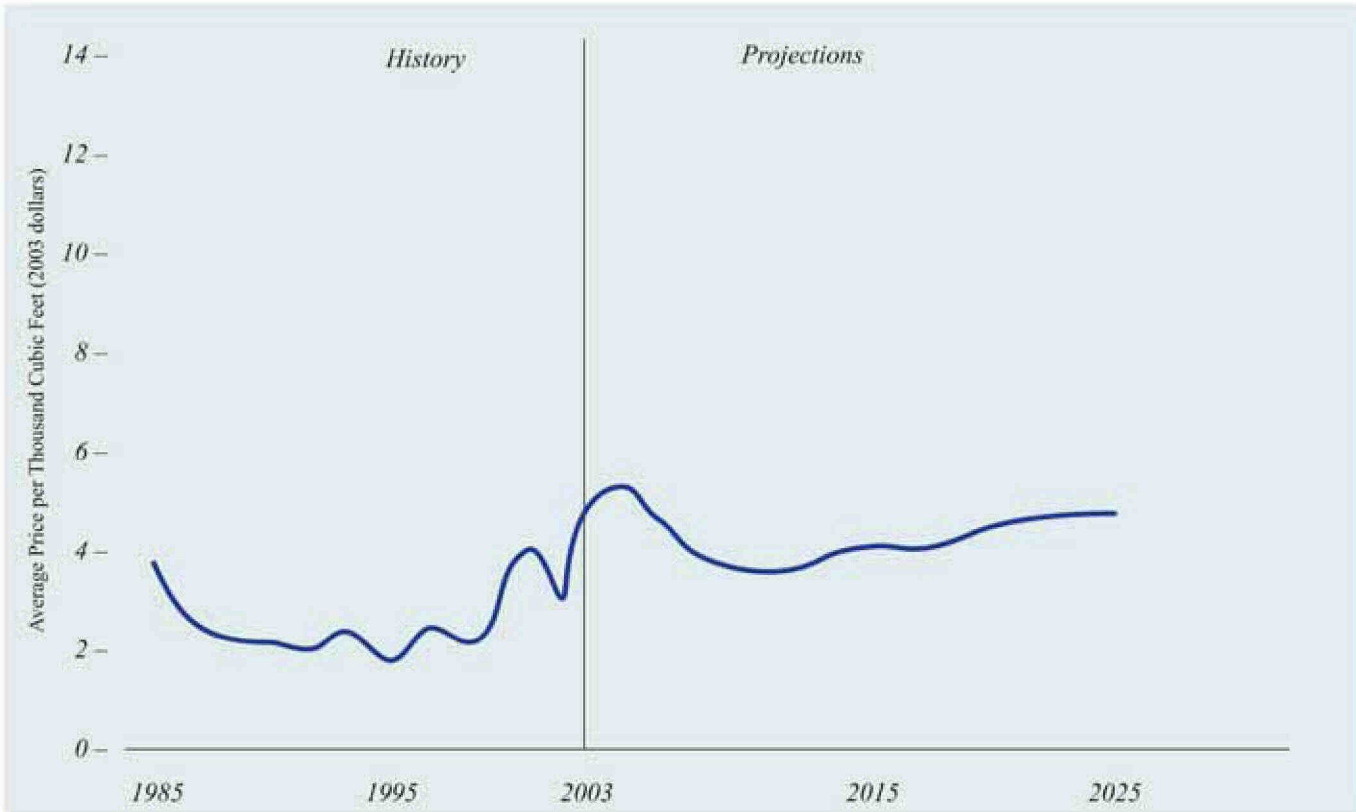
While the data above speaks to recent issues with natural gas pricing, there is a need for LNG to moderate long-run increases in natural gas prices. In its *AEO 2005*, the EIA forecasts that over the longer term, beginning in 2011, wellhead and delivered natural gas prices are projected to increase, largely in response to the higher exploration and development costs associated with smaller and deeper gas deposits in the remaining domestic resource base (*see* Figure 3-4). Gradually rising prices are anticipated over the remainder of the forecast period to 2025. Absent LNG imports, New York and Connecticut, currently positioned at the end of the continental gas transportation system, will be the most affected by this rising price trend.

Need for LNG

The projected growth in natural gas supplies to meet future need depends on unconventional domestic production, natural gas from Alaska, and imports of LNG (EIA 2005a, page 8). LNG imports have become an increasingly important part of the U.S. energy market due, in part, to higher natural gas prices, increased competition, and technological advances that have lowered the costs for liquefaction, shipping, storing, and regasification (EIA 2004, page 39). Global energy providers continue to increase natural gas exports by linking large, isolated gas reserves to existing global markets that are in need of a diversified and reliable natural gas supply. The lower supply costs of LNG, the increase in demand for natural gas, and the projected declines in domestic natural gas reserves all point to LNG imports playing an integral part in meeting the long-term energy needs of the U.S. in general, and New York and Connecticut in particular.

According to the EIA's *AEO 2005* (EIA 2005a), natural gas consumption in the U.S. is currently about 23 tcf per year and is expected to increase to about 31 tcf per year by 2025. Traditional natural gas supplies from the Gulf Coast and western Canada will meet only 75% of this increase in demand, necessitating the acquisition of additional supplies from Alaska and from other parts of the world in the form of LNG. In order to offset the imbalance between domestic supply and consumer demand, LNG imports to the U.S. are projected to increase from 0.4 tcf in 2003 to more than 6.4 tcf by 2025 (EIA 2005a, page 8).

The U.S. in general and the New York and Connecticut region in particular face a projected critical period over the next 10 to 15 years in meeting the energy needs of consumers. Volatility of natural gas prices experienced in New York and Connecticut



SOURCE: EIA 2005a

Figure 3-4 Historic and Projected Natural Gas Wellhead Prices from 1985 to 2025

over the past few years is symptomatic of the growing imbalance between energy demands and available supplies. While continued development of alternative energy sources (e.g., renewables) and investment in energy efficiency programs will help, the region needs a growing supply of natural gas to heat and cool homes, grow the economy, feed industries, and avoid power shortages until these new energy sources can provide sufficient supply to meet demands.

As the cleanest burning fossil fuel, natural gas is the fuel of choice in the U.S. for new power generation, residential heating, and commercial and industrial applications. This is due in part to the efficiency gains of new technologies, lower initial investment costs, relative ease in siting new plants, and lower pollutant emissions. Most of the power load increase over the last several years was served by the introduction of new power plants fired by natural gas and No. 2 fuel oil. U.S. electric utilities consumed approximately 23% of the total natural gas used in the U.S. in 2003 (EIA 2005a, page 95).

Given the critical need for new energy supplies in the Region and ongoing air quality concerns, these energy supplies should be cleaner burning than the fossil fuels that currently supply much of the Region's energy. According to the 2002 New York State Energy Plan (NYSERDA 2002), natural gas demand in the state is expected to grow nearly 38% by 2020 from 2002 levels. This growth is driven largely by electric generation, which itself is projected to grow approximately 23% by 2020. This trend is similar in Connecticut, where almost all new generation capacity (installed or under construction) since 1999 is fired with natural gas.

The Connecticut Energy Advisory Board (CEAB) advocates the enhancement of natural gas infrastructure to facilitate its growing dependence on LNG as a component of New England's natural gas supply (CEAB 2005, page 23). The Connecticut State Energy Plan forecasts that the consumption of natural gas for energy generation will nearly double from 24% in 2002 to 47% by 2008. New York State also supports the development of additional energy supplies and infrastructure to meet its growing energy needs (NYSERDA 2002, page S-4).

Onshore LNG import terminals are currently operating in Everett, Massachusetts; Lake Charles, Louisiana; Cove Point, Maryland; and Elba Island, Georgia. All of these locations have planned expansions of their facilities to meet the growing demand for LNG supplies (EIA 2004, page 91). Additional facilities are proposed in New England and proposed or permitted for construction elsewhere in the lower 48 states, providing LNG imports for the Gulf, Mid-Atlantic, South Atlantic, and Pacific coast states (EIA 2004, page 40) to help meet the need for natural gas in these market areas. However, none of the proposed expansions or new terminal proposals can meet the future demands of the New York and Connecticut markets.

A further discussion of the supply potential of existing and proposed LNG import terminals for the U.S. Northeast is provided in Resource Report No. 10 (Alternatives).

Project Deliveries

The Project will provide 1.0 bcfd of natural gas supply to the Region, with the ability to service a peak demand of 1.25 bcfd. Gas volumes will be delivered to an interconnection point with the IGTS system. From this point, gas can physically flow either south to Long Island and New York City, or north to Connecticut and upstate New York.

Broadwater conducted hydraulic simulations of the IGTS system, which demonstrated that the IGTS system is capable of taking away the Broadwater peak, nominal and lower send-out volumes from the interconnection point. This analysis indicates that flows of up to 600 to 700 mmcfd of natural gas could be physically delivered to Long Island and/or New York City from the Broadwater project. The balance of physical deliveries would be to the north of the interconnection point. Based on Broadwater's analysis, these rates could be achieved without pipeline looping or compression on the IGTS system.

3.1.2 Alternatives Analysis

A detailed analysis of alternatives is provided in Resource Report No. 10 (Alternatives). A summary of that analysis is provided here.

Broadwater evaluated a number of alternatives to and/or for the Project to determine whether these alternatives were reasonably implementable and environmentally preferable to meet the anticipated energy needs of consumers in the Region over the projected critical period during the next 10 to 15 years. To be considered a viable alternative to and/or for the Project, the existing or proposed alternative would need to provide, or directly facilitate provision of, a source of reliable, long-term, and competitively priced natural gas to the Region that is comparable to the Project.

System alternatives considered for the Project included the no action and postponed action alternatives, energy alternatives, and other system alternatives. Conceptual, siting, and technological alternatives considered for the Project included LNG terminal concept and site alternatives, pipeline route alternatives, and equipment or technology alternatives. The in-depth evaluation of each of these potential alternatives is presented in Resource Report No. 10 (Alternatives). A summary of the results of the alternatives analysis is presented below.

3.1.2.1 No Action and Postponed Action Alternatives

The no action and postponed action alternatives are system alternatives that consist of not building and operating, or a delay in building and operating, an LNG facility. The in-depth evaluation of the no action and postponed alternatives is presented in Section 10.3 of Resource Report No. 10 (Alternatives). To summarize, short-term results of the no action and postponed alternatives include avoiding or indefinitely delaying any short-term and long-term potential environmental impacts associated with building and operating an LNG facility. Long-term results of the no action and postponed alternatives are that a source of reliable, long-term, and competitively priced natural gas would not be available to the Region, and consumers will have fewer and potentially more expensive options for obtaining natural gas supplies in the near future and possibly face supply shortages. This is particularly important because renewable energy sources have not been developed sufficiently to meet the anticipated energy needs of the Region. Therefore, potential customers would be forced to choose from among existing energy alternatives.

Use of existing energy alternatives to meet the Region's projected energy demand would have negative environmental and economic consequences, including increasingly higher emission rates of oxides of nitrogen (NO_x), sulfur dioxide (SO_2), mercury, and greenhouse gases from the increased use of fossil fuels such as oil and coal rather than the use of natural gas. Furthermore, the declining availability of traditional and existing natural gas supplies from domestic production will lead to potentially significant threats of shortages and large price increases as the Region competes for supply with other parts of the country. Finally, as a result of the no action and postponed alternatives, the consumers in the Region would not, in the reasonably foreseeable future, benefit from greater energy price stability; the labor force would not benefit from direct and indirect jobs created by the Project; and local communities would not benefit from the half billion dollars that the Project is expected to generate in tax revenues alone over its lifetime.

Thus, the no-action and postponed action alternatives are not reasonable alternatives to the Project and would not preclude the need for the Project.

3.1.2.2 Energy Alternatives

Energy alternatives are also system alternatives, and include both energy source alternatives and energy conservation alternatives. Energy source alternatives include traditional long-term energy sources such as fossil fuels (natural gas, oil, and coal), nuclear energy, and hydroelectric energy, and the development of renewable energy sources such as wind, solar, and biomass power. Energy conservation alternatives include implementing energy conservation programs to alleviate some of the growing demand for energy. The in-depth evaluation of energy source and energy conservation alternatives is presented in Sections 10.3.1 and 10.4.3 of Resource Report No. 10 (Alternatives). These energy source and energy conservation alternatives would result in a variety of effects, which are summarized below.

3.1.2.2.1 Energy Source Alternatives

Energy source alternatives, such as fossil fuels, nuclear energy, hydroelectric energy, and renewable sources such as wind, solar, and biomass energy, will all avoid short- and long-term environmental impacts associated with construction of the Project. However, the selection of energy source alternatives from traditional sources such as fossil fuels will result in short- and long-term impacts that are identical to those listed above for the no-action and postponed action alternatives.

Selection of energy source alternatives from nuclear power and hydroelectric power are unlikely meet the anticipated need for energy in the Region. Nuclear power sources are unlikely to be sited within the Region in the foreseeable future, due to regulatory implementability issues, cost considerations, nuclear waste disposal, and potential public concerns. It is also unlikely that new and significant hydropower sources could be permitted and brought online as reliable alternatives to the natural gas that would be provided by the Project. Selection of energy source alternatives from renewable sources, such as wind, solar, and biomass sources, is unlikely to provide sufficient increases in available energy, despite improvements in technology and declining costs.

Selection of energy source alternatives from electrical energy transmission systems (because most of the projected growth in the demand for natural gas is for electricity generation) would provide additional sources of electric power for the Region. However, these additional sources of energy would fulfill only approximately 11% of the Region's peak electric usage, and this percentage will decrease over time as the demand for electricity grows. Furthermore, these additional sources of electrical energy, which are derived from coal and fuel oil, result in emissions impacts from electric generation activities, and would not be widely available for other uses besides electric generation, such as residential and commercial space heating.

Thus, energy source alternatives are not reasonable alternatives to the Project and would not preclude the need for the Project.

3.1.2.2.2 Energy Conservation Alternatives

Energy conservation alternatives could help and, therefore, offset some of the need for new LNG supplies. However, while energy conservation can play a critical role in the future of the U.S. energy policy, growth projections continue to indicate that the demand for energy, and specifically natural gas, will outstrip cost-effective programs designed to stimulate energy conservation. Therefore, existing conservation programs cannot fully offset the projected growth in demand for energy, and a corresponding demand for natural gas, either nationally or within the Region. With continued economic growth, the growth of electricity demand throughout the U.S., as well as within the Region, will lead to increased natural gas use, despite programs to encourage energy conservation.

Thus, energy conservation alternatives are not reasonable alternatives to the Project and would not preclude the need for the Project.

3.1.2.3 Other System Alternatives

Other system alternatives would make use of other existing or proposed natural gas transmission pipelines, LNG terminals, or electrical transmission systems (cables) to meet the stated objectives of the Project. Selection of one of these system alternatives would make it unnecessary to construct all or part of the Project (although some modifications or additions to an existing or proposed system alternative would be necessary). As a part of its review of potential alternatives to the Project, Broadwater evaluated a large number of existing and proposed natural gas transmission pipeline alternatives and existing and proposed on- and offshore LNG facility alternatives. The in-depth evaluation of these various system alternatives is presented in Section 10.4 of Resource Report No. 10 (Alternatives). These system alternatives would result in a variety of effects, which are summarized below.

3.1.2.3.1 Existing and Proposed Natural Gas Transmission Pipelines

A total of nine existing and proposed natural gas transmission pipeline alternatives were evaluated to determine the feasibility of utilizing or expanding existing transmission pipelines to provide an equivalent amount of natural gas to the Region as an alternative to the Project (see Section 10.4.1 of Resource Report No. 10, Alternatives). Broadwater determined that these existing and/or proposed pipelines would not be able to provide the additional 1.0 bcfd of reliable, long-term, and competitively priced natural gas to the Region, consistent with the Project objectives. Recent experience has shown that natural gas flows into the Region under conditions of peak winter demand already approach the available pipeline capacity. Under these conditions, the supply of natural gas to the Region is constrained, and available gas volumes are allocated to those customers most willing to pay premium prices, resulting in increased price levels and price spikes. Owing to the population density in the Region, expansions of existing infrastructure to accommodate the Project requirements were determined not to be viable alternatives to the Project. Furthermore, expansions of the existing pipeline infrastructure would, in most cases, only add natural gas transmission capacity from existing supply sources and thus would not provide a new source of natural gas supply. As a result, Broadwater believes that while the proposed transmission pipeline alternatives, if constructed, may improve transmission infrastructure flexibility in the Region, they are not reasonable supply alternatives to the Project.

Thus, the existing and proposed natural gas transmission pipeline alternatives are not reasonable alternatives to the Project and would not preclude the need for the Project.

3.1.2.3.2 Existing and proposed on- and offshore LNG facilities

A total of 29 existing and/or proposed on- and offshore LNG facility alternatives were evaluated to determine the feasibility of relying on existing and proposed LNG terminals as alternative sources of reliable, long-term, and competitively priced natural gas to the Region (see Section 10.4.2 of Resource Report No. 10, Alternatives). Broadwater determined that none of these existing and/or proposed on- and offshore LNG facility alternatives would be able to provide the additional 1 bcfd of reliable, long-term, and competitively priced natural gas to the Region, consistent with the Project objectives.

Seventeen existing or proposed on- and offshore LNG facility alternatives are located too far away (i.e., on the Gulf Coast, the Southeastern and Mid-Atlantic U.S., or Eastern Canada) to competitively serve the Region, and would require either new construction or significant expansion of pipeline systems to the Region. Furthermore, many of the existing pipeline systems associated with these alternatives, particularly those existing pipeline systems extending from the Gulf Coast, currently serve alternative markets along their geographic extent, which could reduce the incremental supply available to the Region; would require significant expansion to serve the Region, resulting in significant environmental impacts; and, would be difficult to site and obtain regulatory approvals in view of increasing population density and encroachment along existing pipeline rights-of-way.

Eight other existing or proposed on- and offshore LNG facility alternatives are designed to serve only specific geographic markets (i.e., New England or Eastern Canada) and thus cannot meet the current and projected demands for natural gas in the Region; have limited expansion capabilities; would require construction of new pipeline systems or expansion of existing pipeline systems to meet the needs of the Region, such that new construction may result in significant environmental impacts in comparison with that of the Project; have been denied certification; or are technologically not compatible with, or unable to meet, Project objectives.

Insufficient information is available for the four remaining domestic LNG facilities that have been announced but not formally proposed to allow Broadwater to consider these facilities as viable alternatives to the Project.

Thus, the 29 existing, proposed, and announced (but not formally proposed) on- and offshore LNG facility alternatives are not considered reasonable alternatives to the Project.

3.1.2.4 LNG Terminal Concept and Site Alternatives

LNG terminal concept and site alternatives are considered conceptual and/or siting alternatives for the Project, and included on- and offshore concept alternatives and offshore site location alternatives. The in-depth evaluation of LNG terminal concept and site alternatives is presented in Sections 10.5 of Resource Report No. 10 (Alternatives). These LNG terminal concept and site alternatives would result in a variety of effects, which are summarized below.

3.1.2.4.1 LNG Terminal Concept Alternatives

LNG terminal concept alternatives include on- and offshore concepts. Selection of an on-shore concept alternative will require co-location of an LNG terminal at an existing port facility and/or industrial area at an onshore location in the Region bordering Long Island Sound, but will still result in significant and permanent impacts on nearshore and shoreline environments. Significant shoreline earthwork and nearshore dredging would be required to provide berthing and a turning basin to facilitate access by LNG carriers, or would require the construction of a mooring jetty one mile or more into the Sound to accommodate LNG carriers. An onshore concept alternative would also result in location of the Project, and LNG carriers supplying the Project, close to densely populated areas, resulting in significant perceived safety concerns. Finally, overland pipeline construction to gain access to an interstate natural gas pipeline would present additional environmental concerns.

Offshore concept alternatives include a gravity-based structure (GBS), a shuttle regasification vessel (SRV), and an FSRU. Selection of GBS technology for an offshore concept alternative was not considered a viable option because this technology is generally more economically viable when located in water 60 feet (18 m) or less in depth; requires a location close to the shore, resulting in increased impacts on sensitive nearshore ecosystems, visual resources and aesthetic qualities, and perceived safety concerns due to siting closer to populated areas; requires the establishment of a graving dock for construction activities either in the Sound or overseas, using either greenfield development or expansion of existing facilities, which could result in potential significant environmental impacts within a coastal area, and, in the event of an overseas graving dock, would require additional structural design for the GBS to enable trans-Atlantic shipment that would significantly increase the capital costs of the project; and could potentially require some dredging of the seabed to prepare it for installation of the GBS structure, resulting in long-term impacts on the seafloor.

Selection of SRV technology as an offshore concept alternative was also not considered a viable option because this technology generally increases the length of time needed to offload LNG from SRVs by direct injection into a subsea natural gas pipeline (six days or more, versus approximately 18 hours using standard LNG carriers); requires the construction of at least three offloading buoys over a significantly greater area; does not provide on-site storage capability, such that disruption of the shipping supply chain would result in an immediate inability to deliver a reliable source of natural gas to the Region; and requires location in water that is at least 130 feet (40 m) deep, which is not available within the Sound in a practical location with a viable pipeline length for injection, such that the location of an offshore LNG terminal based on SRV technology would need to be placed in an Atlantic Ocean location.

Thus, an offshore LNG terminal concept alternatives based on FSRU technology is the preferred alternative for the Project.

The off-shore terminal option selected, based on FSRU technology, is the best practicable alternative which meets the Project's purposes and which appropriately balances all of the public interests in the Project. Environmental impacts on the Long Island aquatic system from the proposed FSRU will be less than the expected impacts from the other alternatives analyzed. At the same time, the FSRU terminal, when operational, will help meet vital energy needs in the area served.

3.1.2.4.2 LNG Terminal Site Alternatives

A total of 24 on- and offshore LNG terminal site alternatives were evaluated to determine the preferred location for the Broadwater LNG terminal (see Section 10.6 of Resource Report No. 10, Alternatives). Broadwater determined that 16 on- and offshore terminal site alternatives, including two offshore LNG terminal site alternatives and their associated subsea pipelines in the Atlantic Ocean, were in locations that contained significant constraints. These constraints included unsuitable metocean (weather and marine related) conditions; proximity to densely populated areas; potentially significant impacts on other users of the Sound; proximity to, and potentially significant impacts on, sensitive environmental resources; potentially significant dredging requirements; and/or requiring new pipelines (on both on- and offshore locations) between approximately 55 and 110 miles in length, with accompanying intermediate compressor stations (in both on- and offshore locations) to offset potential pressure losses, along with associated impacts on sensitive nearshore and offshore environments, including construction (including potential dredging) of a jetty and LNG carrier berthing facilities and proximity to densely populated areas on Long Island. Because of these constraints, these 16 on-and offshore locations are not considered viable alternatives for the Project, and were eliminated from further consideration.

The remaining eight on- and offshore LNG terminal site alternatives along or within the Sound were then subjected to a more intensive evaluation that compared potential impacts utilizing differing LNG terminal technology alternatives at each site (GBS versus FSRU) against a broad number of environmental, socioeconomic, technical, and commercial criteria. During this more intensive evaluation, GBS technology was again eliminated as a viable technology alternative at these eight sites because this technology would result in increased impacts on the seafloor and visual resources; its has limited storage capacity; and it would require siting closer to shore (in waters no deeper than 60 feet [18 m]) (see also Section 3.1.2.4.1 above). However, all eight on- and offshore LNG terminal site alternatives were found to be viable alternatives using FSRU technology.

Following the finding that all eight on- and offshore LNG terminal site alternatives were viable sites for the Project using FSRU technology, these alternative sites were then subjected to a second comparative analysis that incorporated information from the site selection process, as summarized above, with detailed environmental and engineering data. This detailed environmental and engineering data included information on water quality, water temperature, soil conditions, air emissions, water discharges, sediment quality, marine ecology/sensitive habitats, noise impacts, visual impacts, coastal zone consistency, safety issues, land use compatibility, population density, connecting pipeline distance, and regulatory implementability.

The results of this second comparative analysis again confirmed that GBS technology was not a viable alternative for any of these eight sites and further indicated that three offshore and the single on-shore LNG terminal site alternatives were no longer considered viable alternative sites for the Project based on FSRU technology. The results also identified seven specific locations (sub-blocks) in the general vicinity of the remaining four offshore LNG terminal site alternatives.

These seven sub-blocks were then subjected to a third comparative analysis using the following critical siting criteria: potential impacts on land use and socioeconomic conditions in adjacent communities (noise impacts, impacts on visual resources, and distance from a public safety standpoint); potential impacts on commercial fisheries and fishing interests; soil and water quality; bathymetry; marine hazards and obstructions; and existing and historic waterways and vessel traffic patterns. Results of this third comparative analysis indicated that six of the seven sub-blocks were not viable alternatives, and these were eliminated from further consideration.

Based on these various comparative analyses, the offshore LNG terminal alternative using FSRU technology is the most viable, environmentally sound, economically feasible, and safest alternative for providing a long-term, reliable natural gas supply to the Region. Also based on these various comparative analyses, Sub-Block 1, located within the central portion of the Sound, was identified as the preferred location for the Project.

The preferred location for the FSRU was selected as the best practicable alternative that meets the Project's purposes, while minimizing adverse environmental impacts to the aquatic system of Long Island Sound."

3.1.2.5 Subsea Pipeline Route and Construction Alternatives

Subsea pipeline route and construction alternatives are also considered conceptual and/or siting alternatives for the Project, and included on- and offshore concept and/or site location alternatives. The in-depth evaluation of subsea pipeline route alternatives is presented in Sections 10.6.1.1, 10.6.1.2, and 10.7 of Resource Report No. 10 (Alternatives). The in-depth evaluation of subsea pipeline construction alternatives is presented in Sections 10.9 of Resource Report No. 10 (Alternatives). These subsea pipeline route and construction alternatives would result in a variety of effects, which are summarized below.

3.1.2.5.1 Subsea Pipeline Route Alternatives

A total of five on- and offshore pipeline route alternatives were included in evaluations to determine the preferred location for the Project within the Sound (see Sections 10.6.1.1, 10.6.1.2, and 10.7 of Resource Report No. 10 (Alternatives). Broadwater evaluated five subsea pipeline route alternatives that were associated with the preferred location of the Project. Using the preferred location of the Project in Sub-Block 1 of the Sound as the start point, and Milepost 18.2 along the IGTS pipeline in the Sound as the end point, these five subsea route alternatives were subjected to a comparative analysis using the following factors: public safety, environmental impacts, land-use constraints, restricted areas, engineering constraints, hazards and obstructions, pipeline integrity, cost efficiency, and regulatory implementability. Key environmental and engineering constrains included population concentrations, fish spawning areas, wildlife and endangered species habitats, historical and archeological sites, restricted areas such as national parks, existing utilities, areas of potential erosion, bedrock, excessively steep slopes, seismic conditions, existing utility corridors, temporary and permanent access, construction schedules, and marine traffic routes and anchorages.

The results of this comparative analysis indicated that four of the five subsea pipeline route alternatives were rejected as viable alternatives for a variety of reasons, including the presence of shallow rock, which would require blasting during construction; potential conflicts with commercial shipping lanes; the need for additional cable crossings; uncertainty regarding contamination of dredge disposal sites; increased potential for nearshore marine habitats due to shallow waters; increased numbers of wrecks; potential sediment contamination; and proximity to the shoreline and to shellfishing beds.

Based on the results of this comparative analysis, the remaining subsea pipeline route was selected as the preferred subsea pipeline alternative to connect the preferred location for the FSRU LNG terminal with the existing IGTS pipeline in the Sound.

3.1.2.5.2 Subsea Pipeline Construction Alternatives

Two subsea pipeline construction alternatives were evaluated to determine the preferred method of construction for the subsea pipeline associated with the Project (see Section 10.9 of Resource Report No. 10, Alternatives). These two construction alternatives consist of conventional marine pipeline installation and dynamically positioned (DP) vessel (also known as a laybarge) marine pipeline installation. The DP vessel marine pipeline installation alternative was rejected as a viable subsea pipeline construction alternative because there are no DP vessels that comply with U.S. cabotage laws (specifically the Jones Act [Section 27 of the Merchant Marine Act of 1920]), which restricts the type of vessel that can be used in pipeline construction in U.S. waters (e.g., vessels must be built in the U.S., owned and controlled by U.S. citizens, and manned by a U.S. crew). In addition, DP vessels are more costly to than conventional laybarges, are in high demand for larger projects, require deeper waters than found in the Sound, and may result in increased water perturbations and associated increased sedimentation in relatively shallow waters such as the Sound.

Three pipeline lowering alternatives (a post-lay subsea plow, a post-lay subsea jet sled, and pre-lay dredging) also were included in the evaluation of the preferred method of construction for the Project. The post-lay subsea jet sled and pre-lay dredging alternatives were rejected as viable pipeline lowering alternatives because they are known to cause greater disturbance to sediments and to disperse sediments over a much larger volume of the water column due to liquefaction of the soil, and/or require wider trenches and wider construction areas, with concurrent increases in the volume of excavated sediment and total areas of impact.

Based on the results of these analyses, conventional marine pipeline installation is the preferred alternative for subsea pipeline construction for the Project, and a post-lay subsea plow is the preferred alternative for pipeline lowering during construction of the Project.

3.1.2.6 Conclusion Regarding Alternatives Analyzed

As demonstrated above, numerous technological, site, and operational alternatives were analyzed before selecting the preferred alternatives for the Project. The FSRU technology, its off-shore location, the subsea pipeline route, dredging and construction methods, and operational techniques were all chosen as practicable, safe, and environmentally sound solutions to meeting energy needs in the Region served. A balancing of all the public interests in the Project supports the preferred alternatives selected."

3.1.2.7 LNG Equipment or Technology Alternatives

LNG equipment or technology alternatives are considered conceptual alternatives for the Project but are associated specifically with the selection of FSRU technology for the preferred offshore LNG terminal concept alternative. The various LNG equipment or technology alternatives evaluated for an FSRU LNG terminal include four vaporization techniques, two mooring system alternatives, two nitrogen supply alternatives, and a ballast transfer system. The in-depth evaluation of the various LNG equipment or technology alternatives associated with an FSRU LNG terminal is presented in Section 10.8 of Resource Report No. 10 (Alternatives). The various LNG equipment or technology alternatives associated with an FSRU LNG terminal would result in a variety of effects, which are summarized below.

The four vaporization technologies that were evaluated to provide a heat source to vaporize LNG include submerged combustion vaporization (SCV), seawater-warmed vaporization, shell and tube vaporization (STV), and air-warmed vaporization, where ambient air temperature heats the LNG. Two of these vaporization technologies, seawater- and air-warmed technologies, were rejected as viable technological alternatives for the Project. Seawater-warmed vaporization was rejected because of regulatory concerns regarding potential impacts on fisheries and because supplemental heating technology would be required to accommodate seasonally cool water temperatures in the Sound. Air-warmed vaporization was rejected because of the lack of industry experience in operating this technology and because a different type of vaporization technology would also have to be installed to accommodate seasonally cool air temperatures in the Region. The remaining two vaporization technologies, SCV and STV technologies, were considered viable alternatives for the Project. However, SCV technology was rejected because STV technology, when used in conjunction with SCR technology, will provide superior emissions control for NO_X and CO, with roughly equivalent thermal and global efficiency. Thus, STV technology, used in conjunction with SCR technology, is the preferred vaporization technology alternative for the Project.

The two mooring system alternatives that were evaluated to support the natural gas send-out pipeline and its utilities and to secure the FSRU included an external turret mooring system and a yoke mooring system. The external turret mooring system alternative was rejected as a viable technological alternative for the Project because it requires anchoring at a minimum of six spots on the sea floor, increasing the potential for sea floor impacts, and because the method of anchoring (using horizontal catenary anchor cables up to 3,200 feet [1,000 m] from the turret) is better suited to waters deeper than 165 feet (50 m). The yoke mooring system alternative is better suited to shallow waters such as found in the Sound, with depths of approximately 50 to 100 feet (15 to 30 m), and does not require additional anchoring to secure the tower to the seafloor, resulting in reduced sea floor impacts. Thus, the yoke mooring system is the preferred mooring system alternative for the Project.

The two nitrogen supply and injection technology alternatives that were evaluated for blending with, or injecting into, vaporized LNG, in anticipation of downstream pipeline gas quality requirements, included cryogenic nitrogen plant technology and membraned nitrogen plant technology. The cryogenic nitrogen plant technology alternative was rejected as a viable technological alternative for the Project because it has a larger footprint and distillation column height; is better suited to the high-capacity, high-purity production of nitrogen gas; has long start-up and shut-down periods; requires periodic defrosting of the air separation unit(s); and can be affected by movement of the FSRU, making it less suited to offshore applications without modification. The membraned nitrogen plant technology alternative is better suited to small- to medium-capacity, low-to medium-purity production of nitrogen gas; requires minimal downtime associated with maintenance; is widely available; operates reliably; and does not require modification for use in offshore locations. Thus, membraned nitrogen plant technology is the preferred nitrogen supply and injection technology alternative for the Project.

The feasibility of implementing a ballast transfer system was evaluated as a technology alternative for minimizing the total amount of ballast water intake during LNG transfer operations. However, the ballast transfer system technology alternative was rejected as a viable technological alternative for the Project because there are no LNG carriers in the existing worldwide fleet that are configured to accept ballast water from another facility such as an FSRU LNG terminal, and developing and installing such a configuration into various LNG carriers would be a complex undertaking; coupling and decoupling a ballast transfer system could potentially introduce air into the ballast handling system, resulting in water hammer effects that would be detrimental to this system; and would result in a number of safety issues, including introducing another connection between the FSRU and an LNG carrier (in addition to the liquid and vapor loading arms), installing emergency release couplers on the loading arms of the ballast transfers system, requiring synchronized shutdown of LNG transfer and ballast transfer operations in the event of an emergency shutdown, and increasing the operational complexity of the interface activities between the FSRU and an LNG carrier.

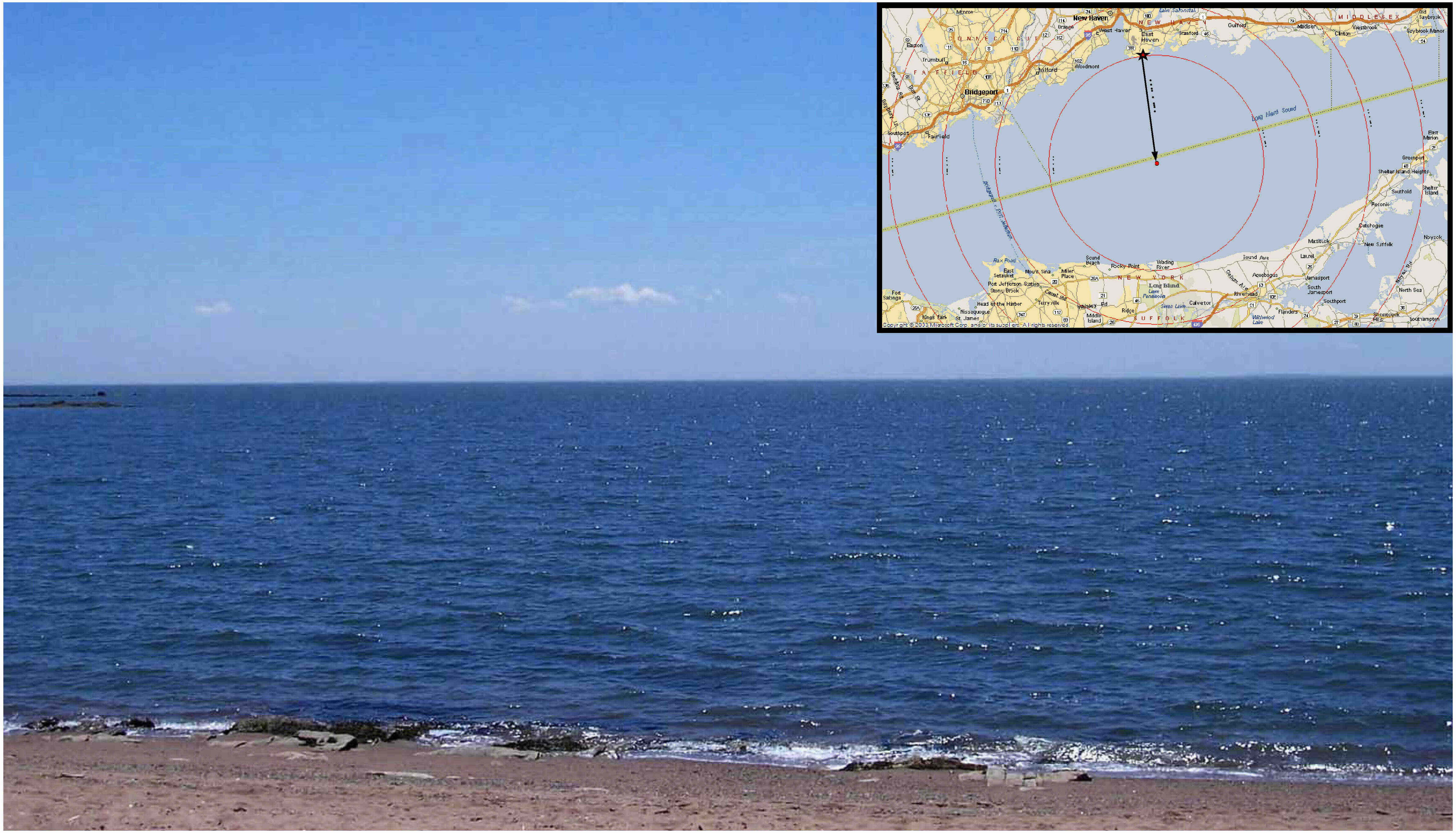
3.1.3 Adjacent Property Owners

All lands underlying state waters fall under the ownership of the State of New York. The Project is located entirely within Long Island Sound on and surrounded by lands underlying state waters that fall under the ownership of the State of New York. Broadwater intends to file applications with the New York State Office of General Services for leases, easements, licenses, permits, or other authorizations that may be required for Broadwater's use of state-owned lands under water, which shall be filed subject to applicable federal and other law and retained rights and without waiver of or prejudice to such law/rights and the rights of Broadwater.

3.1.4 Photographs

Photographs of the offshore component of the Project include views of the proposed offshore LNG terminal location, with simulations that include the Project, from vantage points located on the north shore of the Sound, at East Haven, Connecticut (see Photos 1 and 2), and on the south shore of the Sound on Long Island, near Riverhead, New York (see Photos 3 and 4). Photographs of the two alternative locations for the onshore component of the Project include aerial and oblique photographs of the Greenport, New York, location (see Photos 5 and 6) and the Port Jefferson, New York, location (see Photos 7 and 8).

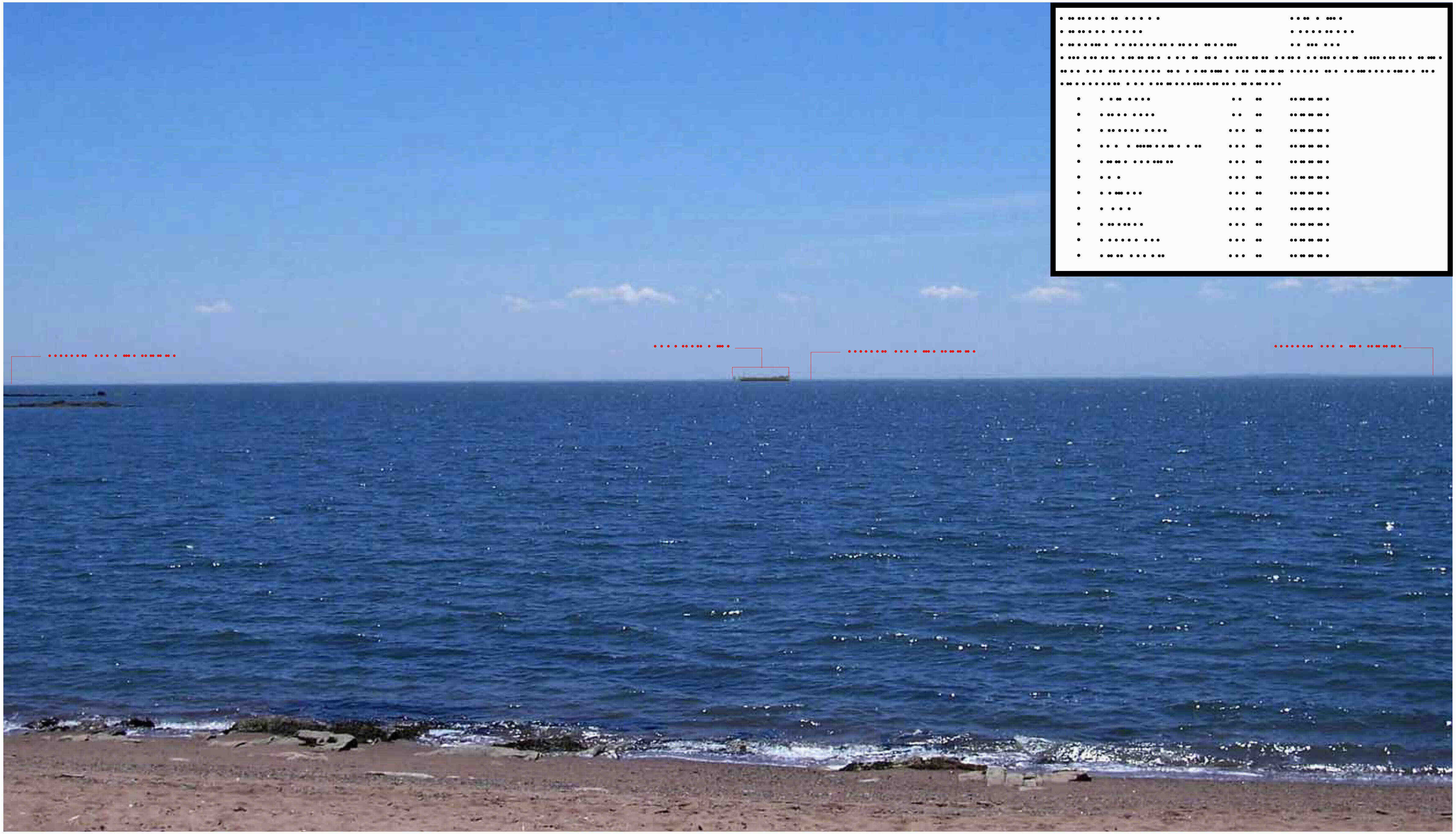
In addition to the aboveground photographs of the onshore and offshore components of the Project, please refer to the video documenting subsea (underwater) conditions at the location of the offshore component of the Project, which is included as Appendix D of Resource Report No. 3 (Fish, Vegetation, and Wildlife).



SARATOGA ASSOCIATES

Photo 1

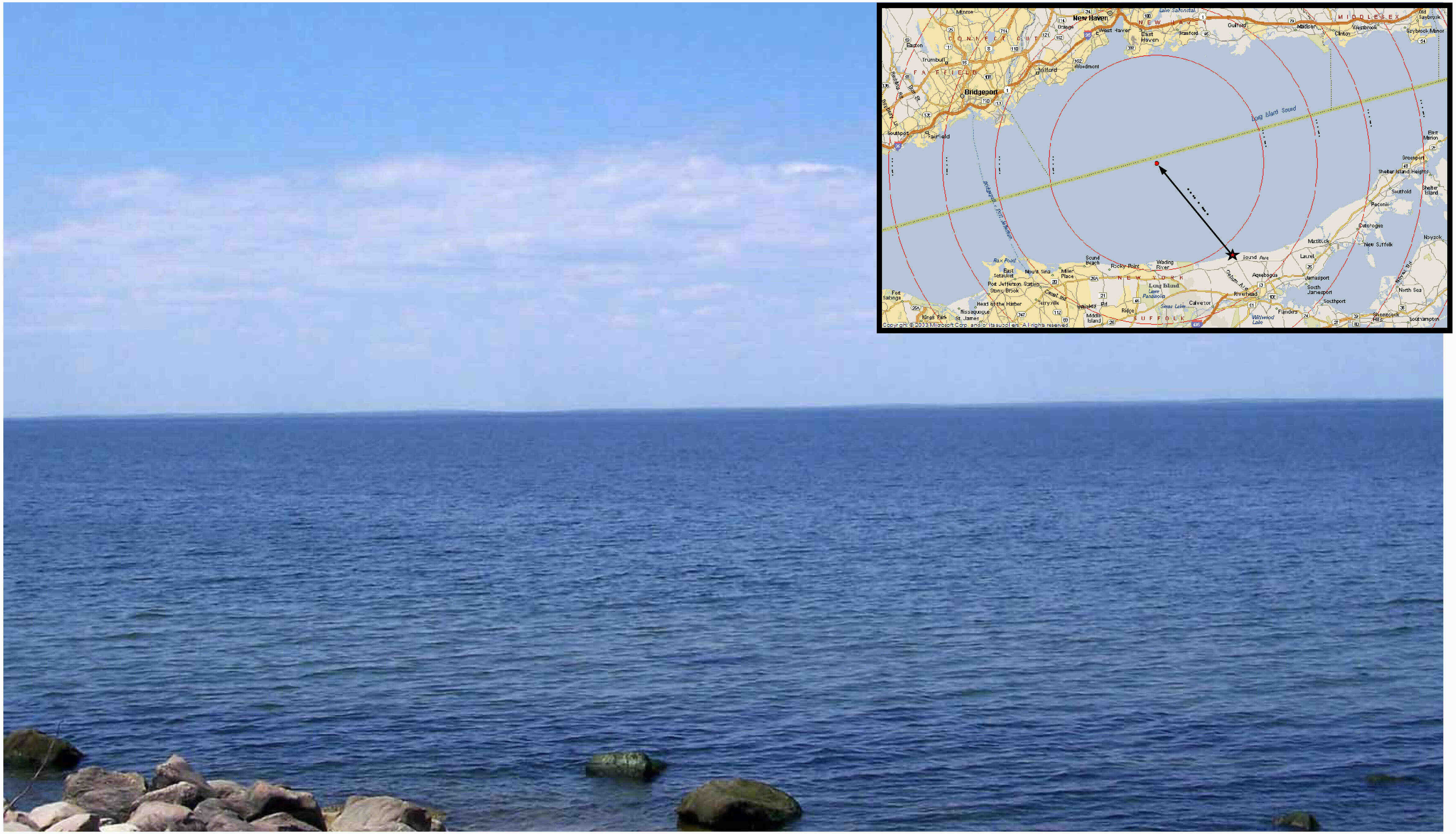
BROADWATER



SARATOGA ASSOCIATES

Photo 2

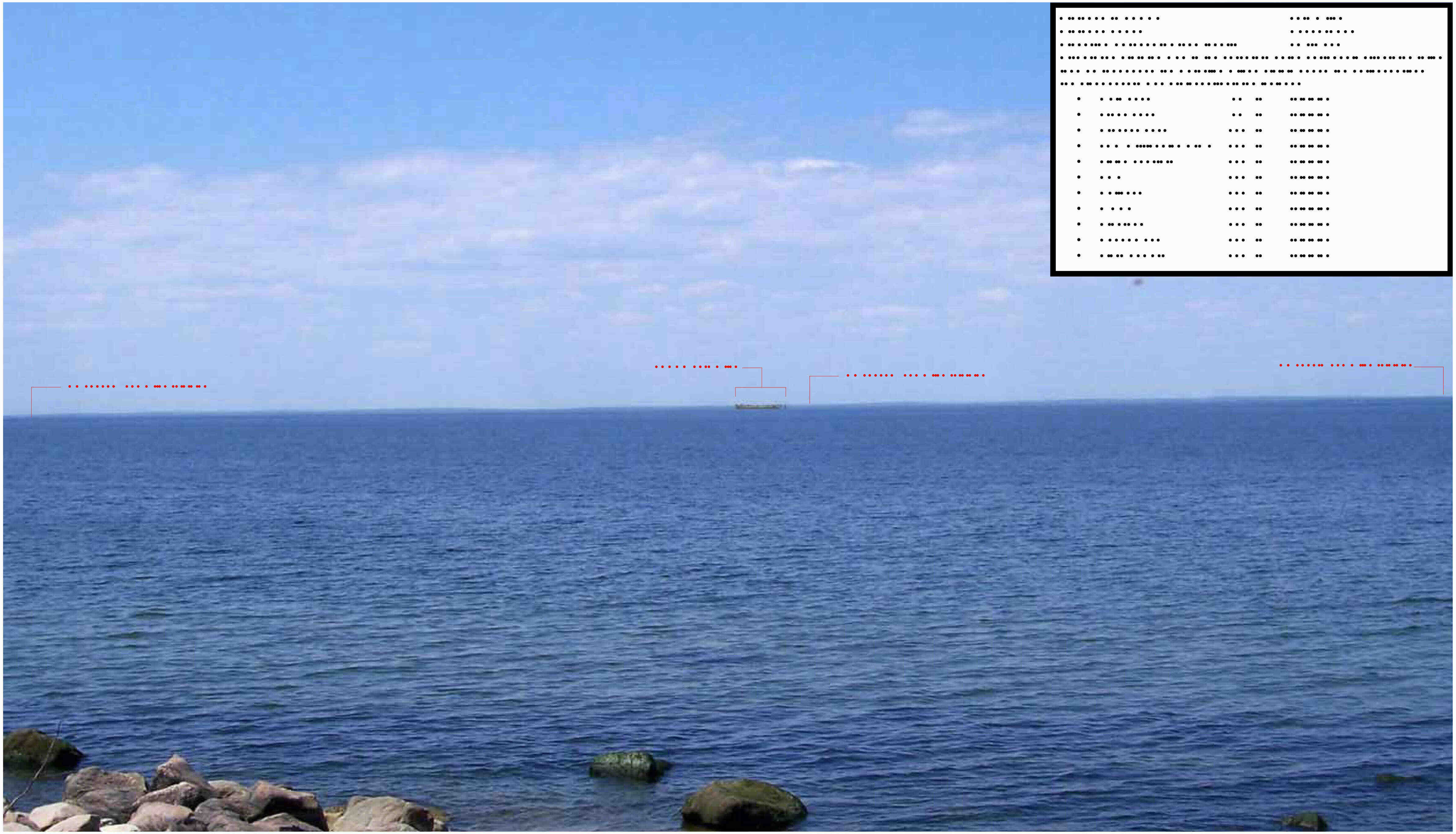
BROADWATER



SARATOGA ASSOCIATES

Photo 3

BROADWATER



SARATOGA ASSOCIATES

Photo 4

BROADWATER

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Source: NYS Digital
Orthoimagery Program, 2004.

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DRAFT

Proposed Onshore
Greenport, NY Facility

Photo 6

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Source: NYS Digital Orthoimagery Program, 2004.

DRAFT

Proposed Onshore
Port Jefferson, NY Facility

Photo 7

Photo 8

3.1.5 Environmental Reports

Resource Reports Nos. 1 through 13 for offshore facilities were filed with FERC on January 30, 2006. Applicable Resource Reports for Onshore Facilities were combined into a single document and also were filed with FERC on January 30, 2006. All Resource Reports are available on the FERC docket. Table 3-2 provides a cross-reference list for potential Project evaluation factors and where they can be found in the Resource Reports.

Table 3-2 Environmental Report Reference Table

Evaluation Factor	Location in Attached Environmental Reports
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	

Table 3-2 Environmental Report Reference Table

Evaluation Factor	Location in Attached Environmental Reports
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]

[illegible]

3.2 DREDGING PROJECTS

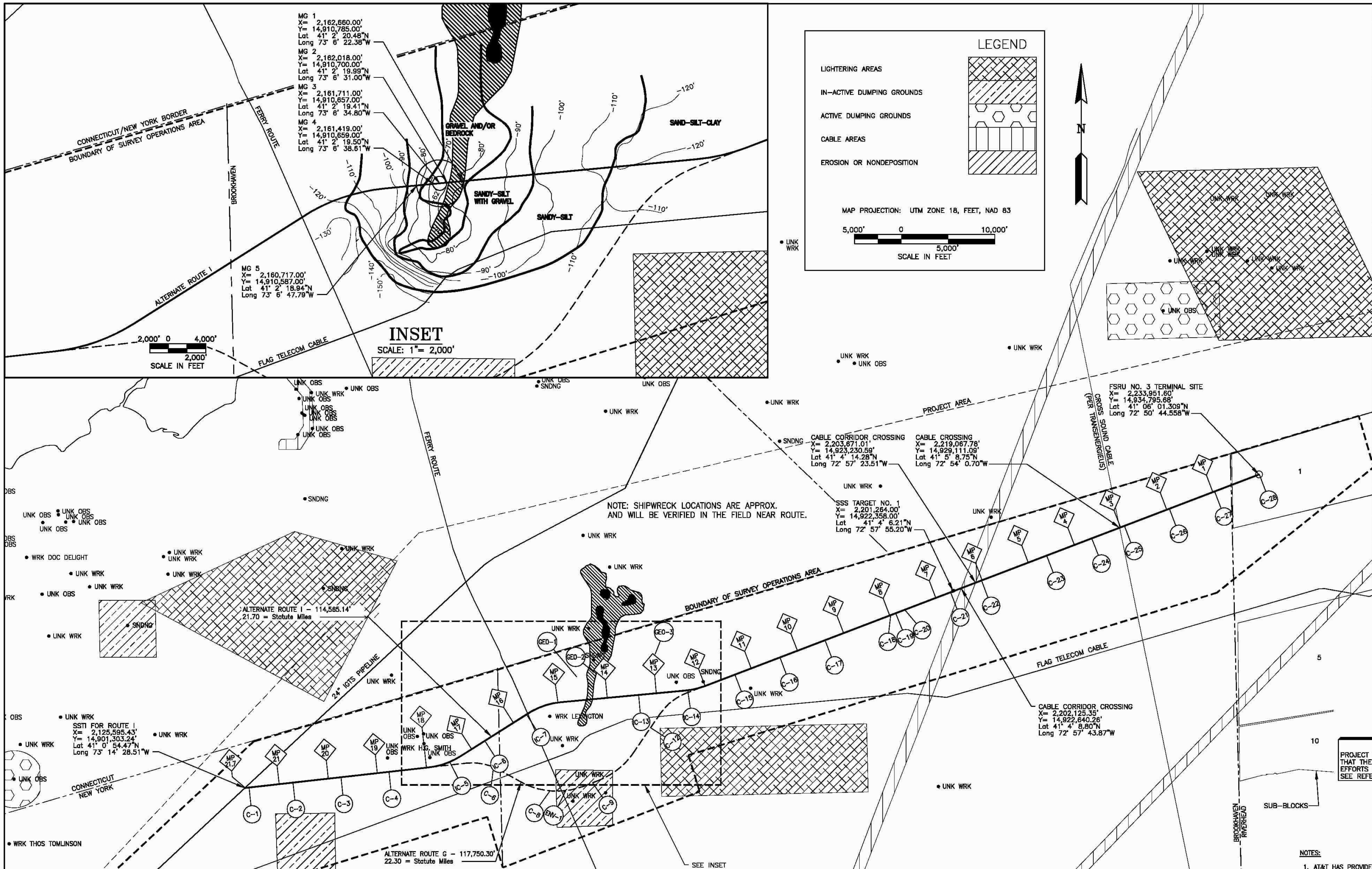
The estimated volume of dredging and estimates of other sediment disturbances associated with installation of the proposed facility are described below in Table 3-3. The depth of disturbance is depicted on Figures 2-7, 2-8, 2-11b, 2-13b, and 2-19b. A description of the installation is included in Section 2.2 (Project Construction). Detailed descriptions of the physical nature of materials to be excavated, excavation methods, locations and dimensions, spoil handling, backfilling, and measures to minimize potential impacts are discussed in Resource Report No. 2 (Water Use and Quality). A summary of the physical nature of the materials to be excavated is provided below in Table 3-4 (Sediment Characteristics Summary), associated geotechnical core locations are indicated on Figure 3-5, and a detailed description is provided in Resource Report No. 7 (Soils).

Table 3-3 Broadwater Pipeline Installation, Summary of Sediment-Related Impacts Along the Pipeline Corridor

Impact Type	Sediment Volume (cu yards)	Impact (acres)	Comment
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	

Installation will be accomplished using the subsea plow for the majority of the route. Generally, where the plow is used, dredged material will be side-cast and left in place. In areas where dredged material will be removed from the site, disposal has not yet been determined due to the lack of predictability of disposal site availability at the time of construction. Disposal in these cases will be at an approved site.

Additional dredging may be required if plowing is determined to be infeasible at the Stratford Shoal crossing. This dredging is described in detail in the Stratford Shoal Contingency Plan included as Appendix C of Resource Report No. 1.



CORE LOCATIONS

CORE 1 (C-1) STA.= 1141+12.50 X= 2,126,047.00' Y= 14,901,338.00'	CORE 20 (C-20) STA.= 405+25.58 X= 2,196,086.00' Y= 14,920,345.00'
CORE 2 (C-2) STA.= 1093+96.28 X= 2,130,729.00' Y= 14,901,907.00'	CORE 21 (C-21) STA.= 352+71.73 X= 2,201,004.00' Y= 14,922,204.00'
CORE 3 (C-3) STA.= 1042+39.58 X= 2,135,857.00' Y= 14,902,451.00'	CORE 22 (C-22) STA.= 317+42.71 X= 2,204,305.00' Y= 14,923,452.00'
CORE 4 (C-4) STA.= 990+76.47 X= 2,140,989.00' Y= 14,903,017.00'	CORE 23 (C-23) STA.= 242+91.81 X= 2,211,263.00' Y= 14,926,117.00'
CORE IC-5 STA.= 924+86.12 X= 2,147,466.00' Y= 14,904,083.00'	CORE 24 (C-24) STA.= 191+26.23 X= 2,216,089.00' Y= 14,927,959.00'
CORE C-6 (C-6) STA.= – X= 2,152,125.00' Y= 14,903,241.00'	CORE 25 (C-25) STA.= 153+94.85 X= 2,219,573.00' Y= 14,929,295.00'
CORE IC-6 STA.= 880+95.17 X= 2,151,247.00' Y= 14,906,307.00'	CORE 26 (C-26) STA.= 102+65.13 X= 2,224,361.00' Y= 14,931,136.00'
CORE IC-7 STA.= 828+19.28 X= 2,155,687.00' Y= 14,909,157.00'	CORE 27 (C-27) STA.= 50+88.78 X= 2,229,197.00' Y= 14,932,982.00'
CORE IC-13 STA.= 705+43.04 X= 2,167,663.00' Y= 14,911,230.00'	CORE 28 (C-28) STA.= 1145+65.14 X= 2,233,971.00' Y= 14,934,799.00'
CORE IC-14 STA.= 652+60.41 X= 2,172,921.00' Y= 14,911,737.00'	CORE ENV-1 STA.= – X= 2,159,885.00' Y= 14,901,002.00'
CORE C-8 (C-8) STA.= – X= 2,158,192.00' Y= 14,900,968.00'	CORE GEO-1 STA.= – X= 2,161,042.00' Y= 14,913,179.00'
CORE C-9 (C-9) STA.= – X= 2,162,752.00' Y= 14,901,810.00'	CORE GEO-2 STA.= – X= 2,162,895.00' Y= 14,913,650.00'
CORE C-12 (C-12) STA.= – X= 2,168,949.00' Y= 14,907,714.00'	CORE GEO-3 STA.= – X= 2,169,429.00' Y= 14,915,582.00'
CORE C-15 (C-15) STA.= 599+45.37 X= 2,177,953.00' Y= 14,913,404.00'	CORE MG-1 STA.= – X= 2,162,660.00' Y= 14,910,785.00'
CORE 16 (C-16) STA.= 599+45.37 X= 2,182,751.00' Y= 14,915,273.00'	CORE MG-2 STA.= – X= 2,162,018.00' Y= 14,910,700.00'
CORE 17 (C-17) STA.= 496+40.99 X= 2,187,579.00' Y= 14,917,081.00'	CORE MG-3 STA.= – X= 2,161,711.00' Y= 14,910,657.00'
CORE 18 (C-18) STA.= 421+31.51 X= 2,194,593.00' Y= 14,919,763.00'	CORE MG-4 STA.= – X= 2,161,419.00' Y= 14,910,659.00'
CORE 19 (C-19) STA.= 415+63.31 X= 2,195,138.00' Y= 14,919,931.00'	CORE MG-5 STA.= – X= 2,160,717.00' Y= 14,910,587.00'

LEGEND:
GEO= GEOTECHNICAL CORE ONLY (3)
C= GEOTECHNICAL AND ENVIRONMENTAL CORES (28)
IC= APPLIES TO ROUTE I

NOTES:

1. AT&T HAS PROVIDED PCS WITH AN AS-BUILT MAP WHICH HAS ONLY ONE COORDINATE POSITION. HOWEVER, PCS WAS TOLD THAT THE CABLE IS WITHIN THE CHARTED ZONE. AVOIDING THE CABLE ZONE IS ADVISED.
2. THE FLAG CABLE WAS NOT IDENTIFIED ON THE GEOPHYSICAL SURVEY RECORD. THE AS-BUILT POSITION SHOWN ON THE PCS SURVEY PLANNING MAP IS THE ONLY AVAILABLE LOCATION.
3. THE CROSS SOUND CABLE LOCATION IS PROVIDED BY TRANSENERGIEUS.
4. THE IGTS PIPELINE LOCATION THAT IS SHOWN ON THE PCS SURVEY PLANNING MAP IS VIRTUALLY THE SAME FOR BOTH THE TESLA 2005 SURVEY WORK AND THE 1999 SURVEY.

ADDITIONAL REFERENCE DRAWINGS:

STATE COUNTY BOUNDARY	CREATED BY ECOLOGY AND ENVIRONMENT, INC – DIGITIZED OFF OF USGS TOPO
TAX BOUNDARY	CREATED BY ERM, PROVIDED BY ECOLOGY AND ENVIRONMENT, INC.
PROJECT AREA	CREATED BY ERM, PROVIDED BY ECOLOGY AND ENVIRONMENT, INC., EDITED BY PROJECT CONSULTING SERVICES, INC.
SHORELINE	CREATED AND DOWNLOADED BY ECOCOLOGY AND ENVIRONMENT, INC. AT THE NOAA COASTLINE EXTRACTOR WEBPAGE, http://rimmer.ngdc.noaa.gov/mgg/coast/getcoast.html NOAA/NOS
COASTAL BOUNDARY	NYS DEC – 2003, PROVIDED BY ECOLOGY AND ENVIRONMENT, INC.
LIGHTERING AREAS	HARDCOPY REPORT MAPS, PROVIDED BY ECOLOGY AND ENVIRONMENT, INC.
FLAG TELECOM CABLE	FLAG TELECOM
TESLA OFFSHORE	OBSTRUCTIONS WITHIN SURVEYED AREA AND FSRU TERMINAL SITES AND IGTS SUBSEA TIE-IN SURVEY, BATHYMETRY, AND SEDIMENT

REFERENCE DRAWINGS

DRAWING NO.	TITLE	DRAWING NO.	TITLE
12363	CONNECTICUT – NEW YORK, LONG ISLAND SOUND WESTERN PART, NOAA CHART, 39TH ED.,	NEW YORK – CONNECTICUT BORDER	www.senate.state.ny.us, CLICK ON BILLS AND LAWS, CLICK ON LAWS OF NEW YORK,
	DATED JULY 15/00		CHOOSE "STATE", CHOOSE ARTICLE 2, SEE SECTION 2 (CONNECTICUT BOUNDARY)
12354	CONNECTICUT – NEW YORK, LONG ISLAND SOUND EASTERN PART, NOAA CHART, 41ST ED.,	SUB-BLOCK 1	EXCERPT FROM FUNCTIONAL REQUIREMENTS – REV 4 IN APPENDIX D
	DATED APRIL 13 & 24/04	SUB-BLOCKS	PROVIDED BY ERM, EDITED BY ECOLOGY AND ENVIRONMENT, INC. AND PROJECT CONSULTING SERVICES, INC.
US-100	IROQUOIS GAS TRANSMISSION SYSTEM PIPELINE ALIGNMENT DRAWINGS, KEY MAP,	WRECKS, INACTIVE & ACTIVE DUMPING AREAS,	NOAA ELECTRONIC CHARTS, 2003 PROVIDED BY ECOLOGY AND ENVIRONMENT
	DRAWING INDEX & GENERAL MAP, REV A, DATED 2-26-91	CABLE AREAS, MARINE FARMS, ANCHORAGE AREAS	
TABLE 4.2.1-1	IROQUOIS GAS TRANSMISSION SYSTEM PIPELINE ALIGNMENT DWGS, PIPELINE ROUTE COORD., POINT P.I. 1	12354 – 1 OF 1	CROSS SOUND CABLE, THALES GEOSOLUTIONS, MAY 2002, PROVIDED BY TRANSENERGIE US LTD.

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHK'D	ENG	APP
A	4-7-05	PRELIMINARY, FOR SURVEY INFORMATION	J.E.F.	J.H.R.	J.H.R.	T.O.
B	4-11-05	REVISED CORES AND LEGEND	J.E.F.	J.H.R.	J.H.R.	T.O.
C	4-14-05	REVISED LOCATION OF CORE 21	J.E.F.	J.H.R.	J.H.R.	T.O.
D	4-21-05	ADDED ROUTE I, REVISED IC-5, IC-6, IC-7, IC-13, AND IC-14 CORE LOCATIONS, AND REVISED STATIONING	J.E.F.	J.H.R.	J.H.R.	T.O.
0	5-17-05	AS-SAMPLED CORE LOCATIONS	J.E.F.	J.H.R.	J.H.R.	T.O.

BROADWATER
BROADWATER ENERGY

DRAWN BY J.E.F.	DATE 4-5-05	SURVEY MAP OF AS-SAMPLED GEOTECHNICAL CORE LOCATIONS FOR ROUTE I & G LONG ISLAND SOUND, NEW YORK
CHECKED BY	DATE	
DRAFT. SUP.	DATE	
ENGR.	DATE	
AFE#	VALVE SECTION	
FILE NO. 05032-009.dwg	SCALE 1"= 5,000'	DWG. NO.: 05032-009 REVISION 0

PLOT DATE: 05-26-05 15:01 05032 12 J.E.F.

3.3 FILLING ACTIVITIES

The proposed facility will require the placement of clean fill from an approved location at the FSRU and IGTS tie-in locations and at utility crossings. The volume of fill will be consistent with the volume of material removed from these areas as listed in Table 3-3 Broadwater Pipeline Installation, Summary of Sediment-Related Impacts Along the Pipeline Corridor. Fill material will be added through the use of drop tubes to ensure accurate placement of the fill material into the pipeline trench. Where concrete mattresses are used, diver-assisted placement will be used to place the mattresses where appropriate. Additional fill material may be required at Stratford Shoal if dredging is required at this location. Additional information regarding dredge and fill at Stratford Shoal is included in the Stratford Shoal Contingency Plan included as Appendix C of Resource Report No. 1 (General Project Description). In all other areas, the trench will be allowed to naturally backfill with material from the spoil piles and material deposited through natural sedimentation.

3.4 MOORING FACILITIES

The proposed facility is not a mooring facility and does not include the construction or rehabilitation of recreational mooring facilities or any mooring facilities that could be used for recreational purposes. The Project does include mooring components as described below.

The proposed FSRU will be moored in place using a YMS that is attached to a stationary tower structure, which is secured to the seafloor (*see* Figures 2-6 and 2-7 for depictions of the YMS). The YMS will provide mooring only for the FSRU facility.

The LNG carriers will be moored to the FSRU facility at a single berth located amidships on the starboard side of the FSRU. The berth can accommodate one LNG carrier with a capacity in the range of 125,000 up to a potential future capacity of 250,000 m^3.

Supply and crew transport vessels will require berthing facilities at the FSRU and at the waterfront to facilitate the transportation of people and materials between the FSRU facility and shore. These vessels will be moored to berths on the port side of the FSRU. Onshore/waterfront facilities will be required that allow berthing for up to four tugs. Broadwater anticipates leasing all onshore facilities, using existing facilities to the extent practicable.

The YMS will be installed on and above underwater lands owned by the State of New York, for which a lease or approval authorizing use or occupancy of such lands will be obtained from the New York State Office of General Services. The mooring facility is described in detail in Resource Report No. 1 (General Project Description). Section 1.3.2.4 of Resource Report No. 1 provides detailed information on the location and description of the yoke mooring system. Section 1.3.2.6 of Resource Report No. 1

Table 3-4 Sediment Characteristics Summary

Station No.	MP	Water Depth (ft)[a]	Maximum Vibracore Penetration (ft)	Maximum Geotech Vibracore Recovery (ft)	Maximum CPT Penetration (ft)	Sediment Type at surface (based on Poppe et al. 2001)	Sediment Type, Top to Bottom (based on summary of core description)	Sediment Type, Top to Bottom (based on geotechnical testing)
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Table 3-4 Sediment Characteristics Summary

Station No.	MP	Water Depth (ft)[a]	Maximum Vibracore Penetration (ft)	Maximum Geotech Vibracore Recovery (ft)	Maximum CPT Penetration (ft)	Sediment Type at surface (based on Poppe et al. 2001)	Sediment Type, Top to Bottom (based on summary of core description)	Sediment Type, Top to Bottom (based on geotechnical testing)
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Table 3-4 Sediment Characteristics Summary

Station No.	MP	Water Depth (ft)[a]	Maximum Vibracore Penetration (ft)	Maximum Geotech Vibracore Recovery (ft)	Maximum CPT Penetration (ft)	Sediment Type at surface (based on Poppe et al. 2001)	Sediment Type, Top to Bottom (based on summary of core description)	Sediment Type, Top to Bottom (based on geotechnical testing)
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[a] [illegible]

[illegible]

- [illegible]
- [illegible]
- [illegible]

provides detailed information on berthing and unloading facilities for LNG carriers. Section 1.5.2 of Resource Report No. 1 provides detailed information on the construction and installation of the tower structure for the yoke mooring system. Section 1.6.2 of Resource Report No. 1 provides detailed information on the operation and maintenance of the yoke mooring system. Onshore facilities are described in greater detail in Broadwater's Onshore Facilities Resource Reports.

4. COASTAL ZONE CONSISTENCY

Broadwater is in the process of completing the coastal zone consistency determination (CZCD) for submission to the New York State Department of State (NYSDOS). Broadwater anticipates submitting a determination to NYSDOS by the end of March 2006. Upon completion, Broadwater will forward a copy of the CZCD, including Broadwater's Federal Consistency Assessment Form, to the USACE for consideration with this permit application.